ELECTRIC POWER IN CANADA 1991

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ELECTRIC POWER IN CANADA 1991

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The Electricity Branch congratulates the Geological Survey of Canada on the occasion of its 150th anniversary and wishes it continued success in the future.

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1. THE ELECTRIC POWER INDUSTRY IN CANADA

INDUSTRY STRUCTURE

The modern electric power industry in Canada began in 1884. Today electricity is vital to almost every aspect of the Canadian economy and is projected to continue to expand its role over the next decade. From 1947 to the end of 1991, net electricity generation increased at an annual average rate of 5.5 per cent, compared with real Gross Domestic Product of 4.2 per cent, and total population growth of 1.8 per cent. Canada's electric power industry is made up of provincial Crown corporations, investor-owned utilities, municipal utilities and industrial establishments. The federal government plays a very small role in capacity ownership and generation.

Under the Canadian constitution, electricity is primarily within the jurisdiction of the provinces. As a result, Canada's electrical industry is organized along provincial lines. In most provinces the industry is highly integrated, with the bulk of the generation, transmission and distribution provided by a few dominant utilities. Although some of these utilities are privately owned, most are Crown corporations owned by the provinces. The dominant utilities are listed in Table 1.1.

Among the major electric utilities, eight are provincially owned, four are investor owned, two are municipally owned, and two are territorial Crown corporations. In 1991, provincial electric utilities owned about 84.9 per cent of Canada's total installed generating capacity and

Table 1.1. Canada's major electric utilities by province

Province	Utility	Ownership
Newfoundland	Newfoundland and Labrador Hydro	Provincial
	Newfoundland Light & Power Co. Ltd.	Private
Prince Edward Island	Maritime Electric Co. Ltd.	Private
Nova Scotia	Nova Scotia Power Corporation	Provincial
New Brunswick	New Brunswick Electric Power Commission	Provincial
Quebec	Hydro-Québec	Provincial
Ontario	Ontario Hydro	Provincial
Manitoba	The Manitoba Hydro-Electric Board	Provincial
	City of Winnipeg Hydro-Electric System	Municipal
Saskatchewan	Saskatchewan Power Corporation	Provincial
Alberta	Alberta Power Ltd.	Private
	Edmonton Power	Municipal
	TransAlta Utilities Corporation	Private
British Columbia	British Columbia Hydro and Power Authority	Provincial
Yukon	Yukon Energy Corp.	Territorial
Northwest Territories	Northwest Territories Power Corporation	Territorial

Source: Energy, Mines and Resources Canada.

produced about 81.3 per cent of total generated electricity. The four investor-owned utilities accounted for 6.1 per cent of all Canadian electric utility capacity and produced about 7.6 per cent of total electricity. Municipally owned utilities accounted for 1.5 per cent of capacity ownership, and produced 1.1 per cent of total generated electricity. The two territorial Crown corporations accounted for 0.3 per cent and 0.2 per cent of capacity and generation respectively.

In addition to the 16 major electric utilities, there are about 60 industrial establishments generating electricity mainly for their own use. A few also sell energy to municipal distribution systems or utilities. These industries are concentrated in the pulp and paper, mining and aluminum smelting sectors. In 1991, industrial establishments owned about 5.9 per cent of total capacity and produced about 8.2 per cent of total generated electricity in Canada, as shown in Table 1.2.

As well as the major electric utilities and industrial establishments, there are about 364 smaller utilities across Canada, of which 87 per cent are located in Ontario. Most of these small utilities are owned by municipalities. They do not own generating capacity; instead, they usually purchase power from the major utility in their province. Several small investor-owned utilities, however, have their own generating capacity. In 1991, the small utilities accounted for 1.3 per cent of total Canadian capacity and produced 1.6 per cent of electrical energy.

ELECTRICITY AND THE ECONOMY

The electric power industry has a significant presence within the Canadian economy. As indicated in Table 1.3, there were almost 101 000 people directly employed by the industry in 1991, about 1.1 per cent of total Canadian employment. Total revenue increased to about $22.1 billion in 1991. Of this total, approximately $554 million or 2.5 per cent came from export earnings. The electric power industry has

Table 1.2. Electrical capacity and production by utilities and industrial establishments, 1930-1991

	Installed Generating Capacity			Energy Production		
Year	Utilities	Industrial Establishments	Capacity	Utilities	Industrial Establishments	Generation
	(per cent)	(per cent)	(MW)	(per cent)	(per cent)	(GW.h)
1930	83	17	5 573	93	7	19 468
1940	84	16	8 104	91	9	33 062
1950	83	17	11 076	88	12	55 037
1960	80	20	23 035	78	22	114 378
1965	82	18	29 348	77	23	144 274
1970	88	12	42 826	84	16	204 723
1975	90	10	61 352	87	13	273 392
1980	92	8	81 999	89	11	367 306
1985	93	7	97 020	92	8	447 182
1988	94	6	101 055	92	8	490 672
1989	94	6	101 960	92	8	482 152
1990	94	6	102 947	91	9	465 744
1991	94	6	104 631	92	8	489 227

Source: Electric Power Statistics, Volume II, Statistics Canada, 57-202, 57-001.

steadily increased its contribution to Canada's Gross Domestic Product, from 2.3 per cent in 1960, to 2.5 per cent in 1970, to 3.0 per cent in 1980, and 3.3 per cent in 1991.

Total assets of the industry were about $124 billion in 1991, accounting for about 7.2 per cent of the capital stock of the economy, excluding the residential sector. This reflects the capital-intensive nature of the electric power industry. Ontario Hydro, Hydro-Québec and B.C. Hydro were the three largest electric utilities in Canada and, in terms of assets, ranked second, third, and eleventh respectively among all Canadian companies.

CANADIAN ELECTRIC UTILITIES

Newfoundland

In Newfoundland, the generation and distribution of electricity is dominated by two utilities, Newfoundland Light & Power Company Limited (NLPC) and Newfoundland and Labrador Hydro (NLH). Together, NLPC

Table 1.3. Electric utility assets, revenue and employees, 1991

Utility	Assets	Revenue	Employees
	($ millions)	($ millions)	(persons)
Major Utilities			
Newfoundland and Labrador Hydro	2 302	370	1 261
Newfoundland Light & Power Co. Ltd.	522	329	960
Maritime Electric Co. Ltd.	123	77	235
Nova Scotia Power Corporation*	1 984	636	2 556
New Brunswick Electric Power Commission*	3 191	909	3 087
Hydro-Québec	41 851	6 284	26 740
Ontario Hydro	43 244	7 143	35 705
The Manitoba Hydro-Electric Board*	5 206	703	4 461
City of Winnipeg Hydro-Electric System	155	118	620
Saskatchewan Power Corporation	2 951	674	2 274
TransAlta Utilities	3 972	1 001	2 700
Edmonton Power	1 830	367	1 190
Alberta Power Ltd.	1 800	462	1 545
B.C. Hydro and Power Authority*	8 449	1 909	6 070
Yukon Energy Corporation*	99	22	92
Northwest Territories Power Corporation*	165	90	280
Other Utilities	5 903	982	11 730
Canada	123 747	22 076	101 506

** As at March 31, 1991*

Source: Electric utilities' annual reports and NLH serve about 225 000 customers.

NLPC, an investor-owned utility, is the primary retailer of electricity on the island. NLPC was incorporated in 1966 through the amalgamation of St. John's Electric Light Company Limited, United Towns Electric Company Limited and Union Electric Light and Power Company. Approximately 92 per cent of the company's power supply is purchased from NLH, with the balance generated by its own hydro stations. NLPC is a subsidiary of FORTIS Inc., formed in 1987.

NLH is a provincial Crown corporation, whose mandate is to generate and transmit electricity in the province. It was established by an act of the provincial legislature in 1954 and was incorporated in 1975. It is the parent company of a group that includes Churchill Falls (Labrador) Corporation (CFLCo), the Lower Churchill Development Corporation (LCDC), Twin Falls Power Corporation Limited, Gull Island Power Co. Ltd., and the Power Distribution District of Newfoundland and Labrador. NLH has 51 per cent ownership in LCDC; the Government of Canada owns the remaining 49 per cent. Through CFLCo, NLH owns and operates the Churchill Falls plant, one of the largest power facilities in the world. NLH's on-island capacity is generated from oil and hydro sources.

Prince Edward Island

Maritime Electric Company Limited (MECL) is an investor-owned utility that has provided electricity service to Prince Edward Island since 1918. The company owns and operates a fully integrated electric utility system providing for the generation, transmission and distribution of electricity throughout the island. MECL operates two oil-fired generating plants on the island, and has a 10 per cent equity interest in New Brunswick Electric Power Commission's coal/oil-fired No. 2 unit located in Dalhousie, N.B. Two submarine cables link MECL's system with New Brunswick's power grid. MECL is the major distributor on the island, serving about 51 800 customers. A municipal utility in the town of Summerside has its own distribution system and purchases power from MECL.

Nova Scotia

The Nova Scotia Power Corporation (NSPC) was incorporated in 1973. It is a provincial Crown corporation that produces and distributes electricity throughout the province. NSPC generates most of its electricity from thermal energy, with more than 58 per cent of the production coming from coal. The utility also maintains hydro-generation and oil-fired facilities, and purchases power from New Brunswick. The largest portion of the province's total production is derived from the Lingan generating station located on Cape Breton Island. In 1991, NSPC served about 386 000 customers.

New Brunswick

The New Brunswick Electric Power Commission (NB Power) was established by an act of the New Brunswick Legislature in 1920. The mandate of NB Power is to generate and distribute power under public ownership to all areas of the province. The utility owns and operates 14 generating stations, and electricity is generated from a balance of nuclear, hydro and thermal sources. NB Power also purchases energy from Quebec. In 1991, NB Power directly provided electricity to 276 000 customers and indirectly served an additional 40 000 customers through sales to two municipal utilities.

Quebec

Hydro-Québec is a Crown corporation, established by the provincial Legislative Assembly in 1944. It is responsible for the generation, transmission and distribution of most of the electricity sold in Quebec. Almost all of the electricity generated by Hydro-Québec at its stations throughout the province is from hydraulic sources. The utility currently serves more than 3.2 million customers.

Hydro-Québec has six wholly owned subsidiaries: — the Société d'énergie de la Baie James, which carried out the construction of Phase 1 of La Grande complex and which now manages large construction projects for Hydro-Québec; —

Hydro-Québec International, which provides engineering and consulting services abroad for electric power projects; — Cedars Rapids Transmission Company Limited, which owns and operates a transmission line between Quebec and New York State; — Somarex Inc., which was created to finance, construct and operate a transmission line in the State of Maine; — Nouveler Inc., which promotes energy efficiency and alternative energy sources; and — Société 2312-0843 Quebec Inc., which is a partner in the limited partnership société en commandite HydrogenAL II and which, on January 1, 1990 became a partner in the limited partnerships société en commandite HydrogenAL and société en commandite ArgonAL, whose other partner is Canadian Liquid Air Ltd.

Hydro-Québec has a 34.2 per cent interest in Churchill Falls (Labrador) Corporation Limited, which operates the Churchill Falls power plant. It also has a 50 per cent interest in HydrogenAL Inc., HydrogenAL II Inc., and ArgonAL Inc.

Ontario

Ontario Hydro is a provincially owned corporation, established in 1906 by a special statute of the Province of Ontario. Ontario Hydro is a financially self-sustaining corporation without share capital. Bonds and notes issued to the public are guaranteed by the Province. Under the Power Corporation Act, the main responsibility of Ontario Hydro is to generate, supply and deliver electricity throughout Ontario. It also produces and sells steam and hot water as primary products. Working with municipal utilities and with the Canadian Standards Association, Ontario Hydro is responsible for the inspection and approval of electrical equipment and wiring throughout the province.

Ontario Hydro sells wholesale electric power to 315 municipal utilities, which in turn retail it to customers in their service areas. Ontario Hydro also serves directly about 112 large industrial customers and more than 891 000 small business and residential customers in rural and remote areas. In 1991, about 3.7 million customers were served by Ontario Hydro and the municipal utilities in the province. Ontario Hydro operates 80 hydraulic, fossil and nuclear generating stations and an extensive transmission system across the province.

In Ontario, there are also a number of small regional utilities. An example is Great Lakes Power Limited, a private hydroelectric generation and distribution utility operating in Sault Ste. Marie and west of the Algoma district of Ontario. In 1991, the utility served over 10 000 customers in northern Ontario directly, and another 30 000 indirectly.

Manitoba

The Manitoba Hydro-Electric Board (Manitoba Hydro) is a Crown corporation established in 1949 by the provincial legislature. It has broad powers to provide electric power throughout the province and operates under the 1970 Manitoba Hydro Act. Almost all of the province's electric power is produced by Manitoba Hydro at its generating stations on the Churchill/Nelson river system in northern Manitoba. Manitoba Hydro distributes electricity to consumers throughout the province, except for the central portion of Winnipeg, which is served by the municipally owned Winnipeg Hydro. Manitoba Hydro and Winnipeg Hydro operate as an integrated electrical generation and transmission system. In 1991, Manitoba Hydro served more than 375 000 customers directly, and Winnipeg Hydro served over 110 000 customers.

Saskatchewan

The Saskatchewan Power Corporation (SaskPower) is a Crown corporation operating under the 1950 Power Corporation Act. Under the Act, the mandate of SaskPower includes the generation, transmission and distribution of electricity. At the end of 1991, the corporation served more than 411 000 customers with electricity. The bulk of the electricity generated by SaskPower is from thermal sources.

In 1988, the gas operations of the corporation became separate companies within SaskPower. The parent company of the gas operations is the Saskatchewan Energy Corporation (SaskEnergy). In 1989, SaskEnergy became a totally separate company.

Alberta

There are three major electric utilities in Alberta: TransAlta Utilities Corporation, Alberta Power Limited, and Edmonton Power. Together, they supply about 92 per cent of Alberta's electrical energy requirements. All are linked by a transmission network largely owned by TransAlta. The remaining 8 per cent of Alberta's electrical energy is supplied by industry. Over 84 per cent of the electricity generated by Alberta utilities is produced by large coal-fired generating stations.

TransAlta Utilities Corporation, formerly Calgary Power Limited, is the largest investor-owned electric utility in Canada. The company was incorporated under the laws of Canada and has been engaged in the production and distribution of electricity in the Province of Alberta since 1911. About 66 per cent of the electric energy requirements of Alberta are supplied by TransAlta, to over half of the population. In 1991, more than 312 000 customers were served directly by TransAlta, while another 315 000 customers were served indirectly through wholesale contracts. TransAlta has a number of subsidiaries: TransAlta Resources Corporation, its principal subsidiary, holds investment in non-regulated activities including TransAlta Technologies Inc.; TransAlta Energy Systems Corporation which provides building automation and energy management services across Canada; TransAlta Fly Ash Ltd.; Kanelk Transmission Company Limited; and Farm Electric Services Ltd.

Alberta Power Limited, incorporated in 1972, is another investor-owned electric utility in Alberta, and a subsidiary of Canadian Utilities Ltd. The activity of the company is concentrated in east-central and northern Alberta. In 1991, Alberta Power supplied about 18 per cent of total Alberta electricity requirements and served more than 147 000 customers.

Edmonton Power has the largest generating capacity of any municipally owned utility in Canada. Since its creation in 1902, Edmonton Power has kept pace with the growth and development of Edmonton. Although the utility produced about 10 per cent of the electricity requirements of Alberta, it had a 14 per cent share of the total provincial market in 1991, serving more than 235 000 customers. Edmonton Power purchases most of its electricity from TransAlta Utilities and Alberta Power.

British Columbia

British Columbia Hydro & Power Authority (B.C. Hydro) was incorporated in 1962 and is a Crown corporation operating in British Columbia. B.C. Hydro provides electrical service throughout the province, with the exception of the southern interior which is served by West Kootenay Power and Light Company, Limited. B.C. Hydro is the third largest electric utility in Canada. It generates, transmits and distributes electricity to more than 1.2 million customers in a service area which contains more than 92 per cent of the population of the province.

In 1988, B.C. Hydro proceeded with a corporate restructuring that resulted in the privatization of its mainland gas operations and its rail operations, and the creation of a number of subsidiaries. B.C. Hydro International Limited provides consulting services in the areas of engineering and utility operations to Canadian and international customers. British Columbia Power Export Corporation (POWEREX) was established to market the province's firm electricity exports. POWEREX negotiates and administers firm export sales agreements with U.S. utilities and purchase agreements with electricity producers, and will make arrangements with Hydro for services such as transmission facilities. Powertech Labs Inc. was formed to provide research, testing and consulting work for electrical technological development. Westech Information Systems Inc. was created in 1989 to offer a wide range of professional services, including the design, development and maintenance of integrated computer systems. Western Integrated Technologies Inc. was also created in 1989 to provide technical support and data processing operations.

West Kootenay Power is an investor-owned utility supplying electric service in the southern interior of British Columbia. The company generates and distributes hydroelectricity directly to more than 63 000 customers in its service area. It also supplies power to seven wholesale customers, who in turn serve almost 38 000 customers. West Kootenay Power is owned by UtiliCorp United Inc. of Kansas City, Missouri.

Yukon

Two utilities provide electrical service to about 12 000 customers in the Yukon. The largest of these, in terms of revenues and generating capacity, is the Yukon Energy Corporation. It is a territorial Crown corporation that has taken over responsibility for the Yukon assets of the Northern Canada Power Commission (NCPC). The Yukon Development Corporation (the parent corporation of the Yukon Energy Corporation) has entered into a five-year management services agreement with the Yukon Electrical Company Limited (YECL). Under the terms of the agreement, YECL will operate the Yukon Energy Corporation's assets, purchase the electricity generated, and distribute it to the Energy Corporation's customers. The Energy Corporation's customers include all of the Yukon's major industries and 13 per cent of the Yukon's non-industrial customers.

In addition to its responsibilities to the Yukon Energy Corporation, YECL (a subsidiary of Canadian Utilities Limited) also generates and distributes power to its own customers. YECL serves 18 communities in the Yukon, including Whitehorse. It purchases the majority of its electrical requirements from the Yukon Energy Corporation.

Northwest Territories

Electrical service to about 14 000 customers in the Northwest Territories is provided by the Northwest Territories Power Corporation (NWTPC) and Northland Utilities Enterprises Limited (Northland). The largest of these, in terms of revenues and generating capacity, is the NWTPC. It is a territorial Crown corporation, which in 1988 took over responsibility for the Northwest Territories' assets of the NCPC. NWTPC provides electrical service to 51 communities in the N.W.T. and wholesales hydro-power to Northland.

Northland is an investor-owned utility and is a subsidiary of Canadian Utilities Limited. It provides electrical service to seven communities in the south-western region of the N.W.T.

2. CANADIAN ELECTRICITY IN THE INTERNATIONAL CONTEXT

This chapter compares Canada's electricity supply, demand, trade and pricing with those of selected other countries in the world. All data used in this chapter were obtained from the United Nations' Energy Statistics Yearbook 1989, Energy Information Administration of the U.S. Department of Energy, and surveys implemented by the Electricity Branch of Canada's Department of Energy, Mines and Resources.

After the second energy crisis of 1979, world electricity consumption continued to grow faster than petroleum and coal, but slightly less than natural gas. World total net electricity consumption (excluding transmission and distribution losses) rose from 7432 TW.h in 1981 to 10 227 TW.h in 1990, an average annual growth rate of 3.6 per cent. During the same period

Table 2.1. International comparison of installed generating capacity, 1989*

Country	Conventional Thermal	Hydro	Nuclear	Geothermal	Total
			(GW)		
United States	561	89	103	4	758
U.S.S.R.	232	64	37	0	333
Japan	118	37	29	0	185
France	23	25	53	0	100
Canada	**29**	**58**	**12**	**0**	**99**
West Germany	69	7	23	0	98
China	68	30	0	0	98
United Kingdom	58	4	8	0	70
India	50	19	2	0	70
Italy	38	18	1	0	70
Brazil	7	45	1	1	57
Spain	21	16	7	0	50
Australia	29	7	0	0	44
Sweden	7	16	10	0	37
Poland	29	2	0	0	33
Mexico	19	8	0	1	31
Norway	0	26	0	0	27
South Africa	24	1	1	0	27
East Germany	20	2	2	0	26
Czechoslovakia	15	3	4	0	23
World total**	1 723 (64.5%)	617 (23.1%)	322 (12.1%)	8 (0.3%)	2 670 (100.0%)

** Includes the 20 countries with the largest electrical systems.*
*** Total for all 190 countries or areas listed in source reference.*

Source: Energy Statistics Yearbook, 1989, United Nations, pp.330-356.

(1981-90), world petroleum consumption increased from 61 million barrels per day to 66 million barrels per day, an average annual increase of only 0.9 per cent; total world consumption of coal had a steady growth pattern, moving from 4219 million short tons in 1981 to 5171 million short tons in 1990, an average annual increase of 2.3 per cent; and worldwide consumption of natural gas increased from 53 610 billion cubic feet in 1981 to 74 427 billion cubic feet in 1990, an average growth rate of 3.7 per cent.

Canada holds a significant place in the world's electric power industry. Canada is not only a world leader in long-distance electric power transmission, but also the largest hydroelectric power producer, and an important consumer.

INSTALLED GENERATING CAPACITY

At the end of 1989, total world installed generating capacity was

Table 2.2. International comparison of electricity generation by fuel type, 1989*

Country	Conventional Thermal	Hydro	Nuclear	Geothermal	Total
			(TW.h)		
United States	2 163	272	529	17	2 981
U.S.S.R.	1 286	223	213	0	1 722
Japan	518	98	183	1	800
China	473	110	0	0	582
Canada	**128**	**291**	**80**	**0**	**500**
West Germany	271	17	149	0	437
France	52	51	304	0	407
United Kingdom	240	7	65	0	312
India	190	64	7	0	261
Brazil	14	214	2	0	230
Italy	170	34	0	3	207
South Africa	160	1	4	0	165
Australia	133	14	0	1	148
Spain	71	20	56	0	147
Poland	142	4	0	0	145
Sweden	6	72	66	0	144
Mexico	92	23	0	5	120
East Germany	105	2	12	0	119
Norway	1	118	0	0	119
Czechoslovakia	60	4	25	0	89
World total**	7 409 (64.8%)	2 094 (18.3%)	1 884 (16.5%)	39 (0.3%)	11 427 (100.0%)

* *Includes the world's 20 largest electrical energy producers.*

** *Total for all 190 countries or areas listed in source reference.*

Source: Energy Statistics Yearbook, 1989, United Nations, pp.386-412.

about 2670 GW. Of this total, conventional thermal (consisting of installed capacity from coal, oil and natural gas) accounted for 1723 GW (64.5 per cent); hydro 617 GW (23.1 per cent); nuclear 322 GW (12.1 per cent); and geothermal only 8 GW (0.3 per cent). (See Table 2.1.)

North America contained 34 per cent of the world's total installed generating capacity, followed by Europe at 25 per cent, Asia at 20 per cent, the U.S.S.R. at 12 per cent, South America at 4 per cent, Africa at 3 per cent, and Oceania at 2 per cent.

The U.S. electric power industry was the largest in the world, with a total installed capacity of 758 GW, accounting for 28 per cent of the total. The U.S.S.R. was second, with an installed capacity of 333 GW, and Japan was third with 185 GW. The United States led in installed capacity for every fuel type: U.S. conventional thermal accounted for 33 per cent of the world's thermal capacity; hydro for 14 per cent; nuclear for 32 per cent; and geothermal for 50 per cent.

Canada ranked fifth in the world with an installed generating capacity of about 99 GW, accounting for 4 per cent of the world total. In terms of fuel type, Canada's hydro capacity is the third largest in the world, next to the U.S. and the U.S.S.R. Canada's nuclear capacity is sixth in the world, and its conventional thermal capacity is tenth.

Table 2.3. International comparison of per capita electricity consumption, 1989*

Country	kW.h/Person	As Percentage of World Average
Norway	24 728	1 124
Canada	**18 635**	**847**
Iceland	18 004	818
Sweden	17 023	774
Luxembourg	13 976	635
Qatar	12 746	579
Finland	12 604	573
United States	12 100	550
Australia	8 882	404
New Zealand	8 382	381
East Germany	7 348	334
West Germany	7 122	324
Belgium	6 532	297
France	6 515	296
Japan	6 503	296
Austria	6 311	287
U.S.S.R.	5 875	267
United Kingdom	5 669	258
Netherlands	5 249	239
Italy	4 223	192
South Africa	4 048	184
Poland	3 854	175
Spain	3 705	168
Brazil	1 708	78
Argentina	1 604	73
Mexico	1 358	62
Egypt	720	33
China	529	24
India	313	14
Nigeria	94	4
World Average**	2 200	100

** The first ten countries are listed according to their actual global rankings. The remaining countries are given in descending order of consumption; however, since only the most populous countries from each region were selected, the list does not indicate their true global rankings.*

*** Average for all 190 countries or areas included in source reference.*

Source: Energy Statistics Yearbook, 1989, United Nations, pp.414-428.

ELECTRICITY GENERATION

In 1989, a total of 11 427 TW.h of electricity was generated around the world: conventional thermal, mainly from coal-fired stations, accounted for 7409 TW.h (64.8 per cent); hydro 2094 TW.h (18.3 per cent); nuclear 1884 TW.h (16.5 per cent); and geothermal 39 TW.h (0.3 per cent). (See Table 2.2.) Although nuclear accounted for only 12.1 per cent of the world's total capacity in 1989, its energy generation share was 16.5 per cent, indicating that most nuclear stations were operating at a relatively high capacity factor compared with conventional thermal stations and hydro plants.

In 1989, North America accounted for 32 per cent of the world's total net electricity generation; Europe 24 per cent; Asia 21 per cent; the U.S.S.R. 15 per cent; South America 4 per cent; Africa 3 per cent, and Oceania 1 per cent.

About 26 per cent of total world electricity generation took place in the United States in 1989. Its conventional thermal generation was 2163 TW.h, accounting for 29 per cent of total world conventional thermal. The United States was also the largest nuclear energy producer in the world in 1989, with a total of 529 TW.h or 28 per cent of total world nuclear. As a proportion of total national electricity production, however, France's nuclear generation was the largest at about 75 per cent, followed by Belgium at 62 per cent and Sweden at 46 per cent. Canada's nuclear share was a relatively small 16 per cent. The nuclear shares of the United States and the U.S.S.R. were 18 per cent and 12 per cent respectively.

Canada's total electricity production ranked fifth in the world (behind the U.S., the U.S.S.R., Japan and China), with total production of 500 TW.h or 4 per cent of the world total. However, Canada was the largest hydroelectric power producer in the world (with a total generation of more than 291 TW.h), accounting for about 14 per cent of the world's total hydroelectric generation (Table 2.2).

Table 2.4. International comparison of total electricity consumption growth rates, 1986-89

Country	Average 1986-89
	(per cent)
India	9.1
China	9.0
Mexico	7.1
Brazil	6.0
Japan	5.7
Australia	5.4
France	4.7
Italy	4.5
United Kingdom	4.4
United States	4.3
Spain	4.2
Canada	**4.1**
South Africa	3.9
Sweden	2.5
U.S.S.R.	2.3
Czechoslovakia	2.1
West Germany	2.0
Norway	1.8
Poland	1.6
East Germany	1.0
World Total*	4.4

** Total for all 190 countries or areas included in source reference.*

Source: Calculated from Energy Statistics Yearbook, 1989, United Nations, pp.414-428.

PER CAPITA ELECTRICITY CONSUMPTION

World per capita electricity consumption was 2200 kW.h in 1989. North America had the highest average of 8677 kW.h; followed by Oceania at 6934 kW.h; the U.S.S.R. at 5875 kW.h; Europe at 5615 kW.h; South America at 1544 kW.h; Asia at 773 kW.h; and Africa at 487 kW.h.

Canada's per capita electricity consumption ranked second in the world in 1989 at 18 635 kW.h, next only to Norway's 24 728 kW.h. As Table 2.3 shows, per capita consumption varies significantly among countries. Norway consumed more than 11 times the world average; Canada more than eight times; and the United States five times. Nigeria's and India's per capita consumption levels were less than 14 per cent of the world average. Although China was the fourth largest electricity producer in the world, its per capita consumption was only 24 per cent of the world average.

Two principal factors contribute to Canada's large per capita consumption of electricity. Abundant water resources have permitted the development of economical hydroelectric power projects in various regions, making electrical energy relatively inexpensive and plentiful. This has led to relatively high electricity consumption among all energy users, and it has led many electricity-intensive industries to locate in Canada. As well, Canada's northerly location means a long and cold winter, resulting in much

Table 2.5. International comparison of electricity exports, 1989*

Country	Exports** (GW.h)	Production (GW.h)	Percentage of Exports to Production
France	50 261	406 891	12.4
U.S.S.R.	39 253	1 722 000	2.3
Canada	**22 328**	**499 536**	**4.5**
West Germany	21 570	437 000	4.9
Switzerland	20 213	53 766	37.6
Norway	15 159	118 775	12.8
United States	14 695	2 980 775	0.5
Sweden	12 526	143 910	8.7
Poland	10 268	145 467	7.1
Austria	8 235	50 167	16.4
Czechoslovakia	7 728	89 200	8.7
Belgium	7 607	66 869	11.4
East Germany	4 987	118 775	4.2
Spain	4 580	146 590	3.1
South Africa	3 000	164 539	1.8
Yugoslavia	2 596	86 309	3.0
Denmark	2 201	22 757	9.7
Mexico	2 000	119 600	1.7
Hungry	1 875	29 588	6.3
Hong Kong	1 770	27 361	6.5
Zambia	1 500	6 742	22.2
Portugal	1 271	25 548	5.0
Paraguay	1 200	2 789	43.0
Uruguay	1 181	5 749	20.5
Laos	720	1 150	62.6
Total World Exports***	266 111	11 426 727	2.3

** Includes the world's 25 largest electricity exporters.*

*** Includes non-cash exchanges.*

**** Total for all exporting countries or areas listed in source reference.*

Source: Energy Statistics Yearbook, 1989, United Nations, pp.414-428.

electricity being used for space-heating purposes. Currently, about 34 per cent of total households in Canada use electricity for space heating.

TOTAL ELECTRICITY CONSUMPTION GROWTH

World electricity consumption grew by approximately 4.4 per cent annually between 1986 and 1989. Among various regions, Asia had the highest electricity consumption growth rate, at 7.6 per cent for the period 1986-89. It was followed by South America 5.1 per cent, Oceania at 4.9 per cent, North America at 4.4 per cent, Africa at 3.5 per cent, Europe at 3.1 per cent, and the U.S.S.R at 2.3 per cent.

Table 2.4 reports total electricity consumption growth rates during 1986-89, for the 20 largest electricity producers in the world. In general, most of the countries with high consumption growth rates were developing countries. Many of these countries have been engaged in the industrialization of their economies and, as a result, have increased their electrical energy consumption significantly.

Canada was one of the few developed countries with a high electricity consumption growth rate for the same period. Surprisingly, West Germany and Sweden were among the countries with the lowest consumption growth rates in the world, during the past four years.

Table 2.6. International comparison of electricity imports, 1989*

Country	Imports** (GW.h)	Consumption (GW.h)	Percentage of Imports to Consumption
Italy	34 454	241 179	14.3
United States	26 623	2 992 703	0.9
Brazil	22 007	251 187	8.8
West Germany	20 997	436 427	4.8
Switzerland	17 697	51 250	34.5
United Kingdom	13 630	324 859	4.2
Canada	**12 969**	**490 177**	**2.6**
Hungary	12 959	40 672	31.9
Poland	12 059	147 258	8.2
Sweden	12 053	143 437	8.4
Denmark	11 660	32 216	36.2
Czechoslovakia	10 377	91 849	11.3
Finland	9 337	62 567	14.9
France	8 105	364 735	2.2
Romania	7 811	83 662	9.3
Austria	5 902	47 834	12.3
East Germany	5 874	119 864	4.9
Bulgaria	5 434	37 180	14.6
Netherlands	5 274	77 972	6.8
Belgium	5 056	64 318	7.9
Luxembourg	4 566	5 199	87.8
Spain	2 758	144 768	1.9
Portugal	2 436	26 713	9.1
China	1 550	583 510	0.3
Zimbabwe	1 350	9 390	14.4
Total World Imports***	282 173	11 442 789	2.5

** Includes the world's 25 largest electricity importers.*

*** Includes non-cash exchanges.*

**** Total for all importing countries or areas listed in source reference.*

Source: Energy Statistics Yearbook, 1989, United Nations, pp.414-428.

ELECTRICITY TRADE

Electricity exchanges among countries can provide a wide variety of benefits to the consumers and electric utilities of trading countries. Interconnections improve the economics and security of electricity supply, and they reduce the level of capacity needed to meet peak loads. Interconnections also improve the flexibility of electricity supply, making it possible to minimize costs by replacing the highest-cost generation, such as oil-fired generation, with imported hydroelectric energy.

Table 2.7. International comparison of electricity intensity*

Country**	1960	1970	1980	1987	1988	1989
			(kW.h/U.S. $1985)			
Norway	1.52	1.83	1.70	1.65	1.68	1.68
Iceland	0.62	1.05	1.20	1.26	1.25	1.38
Sweden	0.71	0.86	1.06	1.35	1.33	1.30
Luxembourg	0.93	1.56	1.30	1.12	1.30	1.24
New Zealand	0.59	0.84	1.14	1.21	1.33	1.24
Canada	**0.94**	**1.05**	**1.13**	**1.21**	**1.22**	**1.22**
Portugal	0.49	0.60	0.86	1.02	1.05	1.08
Finland	0.44	0.66	0.85	1.03	1.02	0.98
Greece	0.24	0.50	0.74	0.91	0.95	0.96
Turkey	0.19	0.34	0.59	0.73	0.76	0.81
Australia	0.39	0.55	0.70	0.78	0.79	0.80
Spain	0.34	0.50	0.71	0.74	0.72	0.73
Belgium	0.44	0.55	0.66	0.73	0.72	0.71
Austria	0.52	0.58	0.62	0.66	0.65	0.66
United States	0.47	0.62	0.69	0.65	0.65	0.66
Ireland	0.33	0.58	0.66	0.65	0.65	0.64
West Germany	0.43	0.56	0.63	0.65	0.64	0.63
France	0.35	0.42	0.54	0.60	0.63	0.62
United Kingdom	0.53	0.73	0.69	0.63	0.62	0.61
Netherlands	0.30	0.45	0.54	0.56	0.57	0.56
Denmark	0.20	0.39	0.51	0.54	0.53	0.53
Japan	0.43	0.52	0.53	0.49	0.50	0.50
Italy	0.36	0.45	0.48	0.49	0.50	0.50
Switzerland	0.37	0.37	0.44	0.49	0.48	0.49

** Electricity intensity is defined as total electricity consumption per dollar of gross domestic product.*
*** Due to limited availability of data, table includes only OECD-member countries.*

Source: Real gross domestic product in U.S. dollars was obtained from National Accounts, 1960-1990, Department of Economics and Statistics, OECD, February 1992. Electrical energy data were obtained from Energy Statistics Yearbook, United Nations, various issues.

In 1989, a total of 266 TW.h of electricity was exported internationally, accounting for about 2.3 per cent of world production (Table 2.5). These exports took place mainly in North America and Europe, where there are extensive interconnections between electrical generating stations.

Europe, the U.S.S.R and North America accounted for 96 per cent of total world electricity exports in 1989. As shown in Table 2.5, France was the largest electricity exporter in the world in 1989, with a total of more than 50 TW.h, accounting for about 19 per cent of total world exports. The U.S.S.R. was second, accounting for 15 per cent, and Canada was third with 8 per cent.

On the import side, the world total was 282 TW.h, accounting for 2.5 per cent of total world consumption in 1989 (Table 2.6). Again, Europe and North America were the major trading areas, accounting for 89 per cent of total world imports.

Italy was the largest electricity importer in 1989, with a total of about 35 TW.h or 12 per cent of total world imports. The United States was second with 27 TW.h, and Brazil was third with 22 TW.h. Although the United States was the second largest importer, its total imports accounted for only 0.9 per cent of its total consumption. The great majority of U.S. electricity imports came from Canada.

Table 2.8. International comparison of electricity prices in the residential sector, January 1992*

City	Residential Country	Prices (U.S. cents/kW.h)
Lagos	Nigeria	0.68
Seattle	United States	3.73
Portland	United States	5.30
Sydney	Australia	5.42
Winnipeg	**Canada**	**5.54**
Montreal	**Canada**	**5.77**
New Delhi	India	6.05
Calgary	**Canada**	**6.23**
Ottawa	**Canada**	**6.34**
Vancouver	**Canada**	**6.92**
Minneapolis	United States	7.35
Singapore	Singapore	8.02
Toronto	**Canada**	**8.42**
Bankok	Thailand	8.63
Kuala Lumpur	Malaysia	8.69
Houston	United States	9.32
Rotterdam	Holland	9.86
Stockholm	Sweden	10.20
Boston	United States	10.30
Los Angeles	United States	10.37
Sao Paulo	Brazil	10.62
Detroit	United States	11.17
Chicago	United States	11.38
Paris	France	11.81
Taipei	Taiwan	12.03
Geneva	Switzerland	12.15
Mexico	Mexico	12.85
Brussels	Belgium	12.96
New York	United States	13.20
London	United Kingdom	13.62

** Based on typical monthly consumption of 750 kW.h.*

Source: Canadian data were obtained from the Electricity Branch, Energy, Mines and Resources Canada. Data for other countries were obtained from a survey undertaken by the Electricity Branch, Energy, Mines and Resources Canada, in February 1992.

ELECTRICITY INTENSITIES

Table 2.7 compares the intensity of electricity use in the economies of all 24 member countries in the Organization for Economic Co-operation and Development (OECD), for the period 1960-89. Electricity intensity is defined as total electricity consumption per dollar of gross domestic product (GDP). To facilitate the comparison, all currencies were converted into U.S. dollars at 1985 price levels and exchange rates. Because of the limited availability of data, only OECD countries are included in the table. Among these countries, Norway had the highest electricity intensity, followed by Iceland, Sweden, Luxembourg, New Zealand, Canada, and Portugal. In 1989, the electricity intensities of these countries were all greater than 1.0 kilowatt hour of electricity consumption per U.S. dollar of GDP, while Japan, Italy, and Switzerland all had electricity intensities equal to or less than 0.5.

Canada's high electricity intensity is a result of several factors, including our relatively cold climate and the fact that a host of electricity-intensive industries are located here. In addition, since the first oil embargo of 1973, a shift in energy use from oil to electricity has occurred in all sectors of the economy.

All 24 OECD-member countries experienced a time-trend increase in electricity intensity between 1960 and 1989, although some minor fluctuations occurred in the United States, the United Kingdom and Japan. In fact,

Table 2.9. International comparison of electricity prices in the commercial sector, January 1992*

City	Country	Commercial Prices (U.S. cents/kW.h)
Lagos	Nigeria	3.32
Seattle	United States	4.34
Portland	United States	5.33
Vancouver	**Canada**	**5.61**
Winnipeg	**Canada**	**5.90**
Minneapolis	United States	5.94
New Delhi	India	5.97
Sao Paulo	Brazil	6.20
Singapore	Singapore	6.50
Ottawa	**Canada**	**6.58**
Calgary	**Canada**	**6.72**
Montreal	**Canada**	**7.66**
Bankok	Thailand	7.98
Mexico	Mexico	8.45
Stockholm	Sweden	8.71
Houston	United States	8.79
Paris	France	8.91
Kuala Lumpur	Malaysia	9.23
Toronto	**Canada**	**9.25**
Taipei	Taiwan	9.40
Chicago	United States	9.95
Rotterdam	Holland	9.97
Boston	United States	10.80
London	United Kingdom	11.53
Sydney	Australia	11.98
Brussels	Belgium	12.41
Detroit	United States	12.66
Los Angeles	United States	12.70
New York	United States	13.20
Geneva	Switzerland	13.92

** Based on a typical monthly billing demand of 100 kW and energy consumption of 25 000 kW.h.*

Source: Canadian data were obtained from the Electricity Branch, Energy, Mines and Resources Canada. Data for other countries were obtained from a survey undertaken by the Electricity Branch, Energy, Mines and Resources Canada, in February 1992.

electricity intensities have been steadily declining since 1970 for the U.K., suggesting that electricity use in producing output has been reduced.

ELECTRICITY PRICES

A comparison of international electricity prices is difficult because of different rate schedules, consumption levels and national currencies. Nevertheless, a reasonable comparison has been established by using average revenue per kilowatt hour in a given sector, under a certain level of consumption, and by converting to U.S. dollars. For a more accurate comparison, purchasing power parities should be used when converted to U.S. dollars. However, such parities are not available for some countries covered in this study and are therefore not taken into consideration.

Tables 2.8, 2.9 and 2.10 summarize electricity prices by sector for 33 cities in 20 selected countries in the world. The results indicate that Canada's electricity prices are highly competitive in the residential, commercial and industrial sectors relative to other countries.

Table 2.10. International comparison of electricity prices in the industrial sector, January 1992*

City	Country	Industrial Prices (U.S. cents/kW.h)
Seattle	United States	2.56
Lagos	Nigeria	3.09
Portland	United States	3.95
Winnipeg	**Canada**	**3.98**
Vancouver	**Canada**	**3.98**
Minneapolis	United States	4.50
Montreal	**Canada**	**4.57**
Calgary	**Canada**	**4.72**
Ottawa	**Canada**	**5.53**
Singapore	Singapore	5.71
Bankok	Thailand	6.22
Sydney	Australia	6.31
Stockholm	Sweden	6.57
Sao Paulo	Brazil	6.79
Toronto	**Canada**	**6.86**
Houston	United States	7.02
Paris	France	7.10
Kuala Lumpur	Malaysia	7.31
Rotterdam	Holland	7.33
Boston	United States	7.40
Taipei	Taiwan	7.69
Los Angeles	United States	7.70
Chicago	United States	7.72
Mexico	Mexico	8.40
Detroit	United States	8.43
New Delhi	India	8.67
London	United Kingdom	8.83
Brussels	Belgium	9.48
Geneva	Switzerland	10.27
New York	United States	10.40

** Based on a typical monthly billing demand of 1000 kW and energy consumption of 400 000 kW.h.*

Source: Canadian data were obtained from the Electricity Branch, Energy, Mines and Resources Canada. Data for other countries were obtained from a survey undertaken by the Electricity Branch, Energy, Mines and Resources Canada, in February 1992.

3. REGULATORY STRUCTURES

FEDERAL REGULATION

Constitutional Authority

Under the Canadian Constitution, legislative authority for electricity generation, transmission and distribution rests primarily with the provinces. Federal authority regarding electricity is restricted to nuclear energy and international and interprovincial trade. Federal responsibility for electricity trade stems primarily from Section 91.2 of the Constitution Act, which gives the federal government broad authority over trade and commerce. Federal control of nuclear energy derives from sections 91.29 and 92.10 of the Act, which permit federal regulation of matters that are declared by Parliament to be for the general advantage of Canada.

Provincial ownership of most energy resources stems from Section 109 of the Constitution Act, which in turn is supplemented by Section 92A of the Act, giving provincial legislatures authority over the development, conservation and management of sites and facilities in the province for the generation and production of electrical energy. Under Section 92A, which was enacted in 1982, the provinces also have authority to make laws regarding interprovincial sales of electricity, as long as such laws do not conflict with federal laws and do not permit discrimination in prices or supplies exported to different parts of Canada.

National Energy Board

The National Energy Board (NEB) is a federal tribunal, created in 1959 by an Act of Parliament. The Board's powers and duties are derived from the National Energy Board Act. Under the Act, the Board advises the federal government on the development and use of energy resources, and regulates specific matters concerning oil, gas and electricity. The Board's jurisdiction over electrical matters is limited to the certification of international and designated interprovincial power lines and the licensing of electricity exports from Canada. The Board has no jurisdiction over imports of electricity.

On September 6, 1988, a new policy concerning the regulation of electricity exports and international power lines was announced. Legislation amending the NEB Act to give effect to this policy (Bill C-23) was proclaimed on June 1, 1990.

Under the new policy, the Government of Canada will continue to authorize international power lines and exports of electricity. Such authorizations will be of two kinds: (i) permits, which will not require a public hearing or Governor in Council approval; or (ii) licences (in the case of electricity exports) or certificates (in the case of power lines), which will require a public hearing and Governor in Council approval.

Authorizations will normally be by an NEB-issued permit unless the Governor in Council, on the advice of the Board, designates the application for certification or licensing. Designations are not likely to occur, except in cases where provincial regulation is deemed to be insufficient -- for example, in cases where the sponsoring province has not complied with relevant federal environmental processes.

Once an application is designated, the Board will conduct a public hearing, and it will not issue a licence or certificate unless it is fully satisfied that the proposal is in the Canadian public interest. Licences and certificates will not be issued unless they are also approved by the Governor in Council.

Under the amendments to the NEB Act, Part III.1 provides for the federal regulation of international power lines. In determining whether to recommend to the Governor in Council designation of a power line, the Board will have regard to all relevant considerations, including: (i) the effect of the power line on other provinces; (ii) the impact of construction and operation of the power line on the environment; and (iii) any other matters that may be specified in the regulations.

In making its determination, the Board will seek to avoid the duplication of measures taken by the applicant and the relevant provincial government(s). The NEB will continue to authorize the general corridor through which an international power line will pass. However, the precise location of the line within this corridor will normally be determined by provincial regulatory procedures, and any expropriation that may be necessary will be done under provincial laws. The only exception to this general procedure will be in cases where the applicant elects to have federal law apply.

The Governor in Council may by order, designate a particular interprovincial power line for regulation in the same manner as international power lines. When power from one province simply enters the grid of another province, there is no federal regulation.

Part VI of the amended NEB Act includes a Division II, which provides for the regulation of electric power exports. The maximum duration of export licences and permits will be 30 years. In determining whether to recommend to the Governor in Council designation of an application for export, the board will have regard to all relevant considerations, including: (i) the effect of the export on provinces other than that from which the electricity is to be exported; (ii) whether those wishing to buy electricity for consumption in Canada have been granted fair market access to the electricity proposed for export; (iii) the impact of the export on the environment; and (iv) any other matters that may be specified in the regulations. In making its determination the Board will also seek to avoid the duplication of measures taken by the applicant and the sponsoring provincial government.

Atomic Energy Control Board

Immediately after World War II, Canada began to study the question of how to encourage the use of nuclear energy for peaceful purposes while at the same time preventing its use for weapons. In 1946, Parliament passed the Atomic Energy Control Act with these objectives in mind.

The Act gave the federal government control over the development, application and use of nuclear energy and established the Atomic Energy Control Board (AECB). The five-member Board administers and enforces the Act, from which it derives its authority to regulate the health, safety, security and environmental aspects of nuclear energy. The AECB reports to Parliament through a designated Minister, currently the Minister of Energy, Mines and Resources.

The Board's primary function is to license Canadian nuclear facilities and activities dealing with prescribed substances and equipment. Nuclear facilities include power and research reactors, uranium mines and refineries, fuel fabrication plants, heavy water plants, waste management facilities and particle accelerators. Prescribed substances include uranium, thorium, heavy water and radioisotopes. Activities relating to such substances, which may be licensed, include production, processing, sale, use, import and export. Before issuing a licence, the AECB ensures that the appropriate health, safety and security standards are met.

The AECB's control also extends to international security of nuclear materials and technology. Through the licensing process, it ensures that nuclear equipment and supplies are exported only in accordance with Canada's obligations under the Treaty on the Non-Proliferation of Nuclear Weapons.

PROVINCIAL REGULATION

As noted above, under the Canadian Constitution the provinces have legislative authority over the generation, transmission and distribution of electricity. In most provinces some form of regulation exists, and most provinces have established regulatory bodies to oversee the utilities, although the degree of supervision varies. The major areas subject to review are rate-setting and the construction of new facilities. The nature of provincial regulation with respect to these matters is described briefly below. The environmental regulations of the provinces are described in chapter 4.

Newfoundland

Newfoundland Light & Power Company (NLPC) and Newfoundland and Labrador Hydro (NLH) are regulated by the Newfoundland Board of Commissioners of Public Utilities. The Board fully regulates the rates and policies of NLPC, including the construction of new facilities. Since 1977, the Board has also had authority under the Electric Power Control Act to review NLH's rates for residential customers. The Board makes recommendations to the Newfoundland Cabinet, which is the final authority for utility rates.

Cabinet is also the final authority with respect to NLH's capital expenditure program. Proposals by NLH for new facilities must receive Cabinet approval before construction can begin. NLPC must receive the approval of the province's Board of Commissioners of Public Utilities before proceeding with the construction of new facilities.

Prince Edward Island

Maritime Electric Company Limited is regulated by the Public Utilities Commission of Prince Edward Island under the provisions of the Electric Power and Telephone Act. The Commission has decision-making authority over electric utility rates in the province and screens all proposals for the construction of new generation and transmission facilities. If the Commission believes that a new facility may adversely affect the environment, a formal environmental assessment review process is initiated. A description of this process is provided in chapter 4.

Nova Scotia

Since 1976, the Nova Scotia Board of Commissioners of Public Utilities, in accordance with the provincial Public Utilities Act, has had full decision-making power over the utility's rates and policies.

The Board's authority extends to the construction of new facilities, and utilities are required to apply directly to the Board when planning new generation or transmission facilities. As part of the review process, the Board holds public hearings, during which the utility presents its proposed project, costs and alternative plans. Members of the public may intervene directly during a hearing. The Board of Commissioners is the final authority on new facilities.

The Nova Scotia Government announced on January 9, 1992 that Nova Scotia Power Corporation is to be privatized starting in July 1992. However, the new investor-owned electric utility will still be regulated by the Nova Scotia Board of Commissioners of Public Utilities.

New Brunswick

As a Crown corporation, New Brunswick Power reports to the provincial government through its chairman, who is a member of the Cabinet. Rates and operations are regulated by a nine-member Board of Commissioners appointed by the Lieutenant Governor of New Brunswick. The utility's chairman and vice chairman sit on the Board. The Board's recommendations are referred to the provincial Cabinet, which is the final regulatory authority. A bi-partisan Crown corporation committee also reviews utility rates and operations annually.

NB Power must receive approval from the Lieutenant Governor in Council before proceeding with the construction of new facilities. Although the Lieutenant Governor in Council is the final authority in this regard, its decision is based upon a recommendation from the Minister of Municipal Affairs and Environment, following an evaluation of the project's possible environmental impacts. New Brunswick's environmental impact assessment process is described in chapter 4.

Quebec

In Quebec, the National Assembly's committee on economics and employment reviews Hydro-Québec's long-term development plan, which includes any proposed rate changes. The committee then makes a recommendation to the Minister of Energy and Resources, who in turn makes a recommendation to Cabinet. Rate increases can therefore be implemented by Hydro-Québec only after they have been approved by Cabinet.

The construction of new facilities by Hydro-Québec can take place only after the utility has received an Order-in-Council from the provincial government. Before an Order is issued, the Department of the Environment and the Department of Energy and Resources must approve plans for the new facility. Other departments and agencies are also consulted.

Ontario

Ontario Hydro is a provincially owned corporation, which reports to the government through the Minister of Energy. The management of Ontario Hydro is under the direction and control of its Board of Directors. Proposed rate changes are referred to the Ontario Energy Board (OEB), through the

Minister of Energy, for examination at public hearings. However, it is the Board of Ontario Hydro that is authorized to set the utility's rates, and it may accept or reject the recommendations of the OEB.

On matters concerning its generation expansion program and transmission facilities, Ontario Hydro is regulated by the provincial Joint Hearing Board. The Board is composed of members from the Environmental Assessment Board and the Ontario Municipal Board. The Joint Board makes a recommendation to the provincial government, and final approval must be given through an Order-in-Council.

Manitoba

Under the Manitoba Crown Corporations Public Review and Accountability Act of 1988, Manitoba Hydro's proposed changes to domestic rates must be reviewed by the Manitoba Public Utilities Board, which holds a public review and makes a final decision on the proposal.

Under the 1988 Manitoba Environment Act, the provincial government must also approve major facility construction. Applications are made to the Minister of the Environment and a full environmental assessment is required. A description of Manitoba's environmental assessment review process is given in chapter 4.

Saskatchewan

Saskatchewan Power Corporation (SaskPower) is governed by a government-appointed Board of Directors that is responsible for the management and operation of the Crown utility. Proposals to increase rates or construct new generation or transmission facilities must be approved by the Board of Directors. The minister responsible for SaskPower is a member of the Board.

Alberta

TransAlta Utilities Corporation and Alberta Power Limited are investor-owned electric utilities in Alberta. They are regulated by the Alberta Energy Resources Conservation Board (ERCB) with respect to the development of generation and transmission facilities, coal mine developments and changes in service areas. Thermal generating stations are issued permits, which are subject to Lieutenant Governor in Council approval, while hydro dam approvals require final authorization through the passage of a bill in the legislature. TransAlta's and Alberta Power's rates are regulated by the Alberta Public Utilities Board, under the provisions of the Public Utilities Board Act of 1980.

As a municipally owned utility, Edmonton Power is subject to the authority of Edmonton Council, as well as the various provincial regulatory bodies. Its rates and financing are regulated by city council, while the ERCB is responsible for the regulation of new generation and transmission facilities.

The three utilities participate in the cost-pooling program of the Electric Energy Marketing Agency (EEMA). The EEMA was established in 1982 by the provincial government to help equalize power costs throughout Alberta. Under EEMA legislation, the utilities' generation and transmission costs are regulated by the Public Utilities Board. The Board also approves the selling prices of electricity to EEMA, which then pools the utilities' costs and resells the power at average prices back to the utilities. Presently, the EEMA is under review by the Alberta Ministry of Energy.

British Columbia

Electricity rate changes in the province of British Columbia require the approval of the British Columbia Utilities Commission (BCUC). Major generation and transmission projects require the approval of the provincial Cabinet. Upon receiving an application to construct a major facility, the government may refer the application to the BCUC for review and a recommended course of action. Projects that obtain Cabinet approval receive an Energy Project Certificate from the province.

Yukon

The Yukon Energy Corporation and the Yukon Electrical Company are regulated by the Yukon Utility Board, under the Public Utilities Act of 1986. Under this Act, the Corporation and Company must file applications for rate changes or facility construction with the Board, which reviews the applications and makes a decision.

Northwest Territories

The Northwest Territories Power Corporation and Northland Utilities Enterprises Limited are regulated by the Northwest Utilities Act of 1989. Under the Act, they must file an application with the N.W.T. Public Utilities Board in order to receive authority for rate changes or facility development. Upon receiving an application, the Board holds a public hearing and then reaches a decision, which is final.

4. ELECTRICITY AND THE ENVIRONMENT

Most, if not all, electricity generation and transmission projects have some impact on the environment. Fossil-fuel generating stations release chemicals into the atmosphere, and dam and transmission line construction projects have an effect on local plant, animal and aquatic life. Governments, industry and other groups in society have recognized the need to assess and reduce these impacts. For their part, federal and provincial governments have established processes that are designed to measure and reduce the environmental consequences of electrical generation and transmission projects.

Despite differences from one province to another in the nature of the environment and in the scale and type of project proposed, there are similarities in the processes developed by the various provincial governments to ensure that the development of electricity generation and transmission projects does as little harm as possible to the environment.

In most provinces, the proponent (a person, company, provincial agency or Crown corporation) is responsible for conducting an environmental assessment of activities. A lead agency (often in the department responsible for the environment) is normally appointed to review this assessment on behalf of the provincial government.

In all provinces, decision-making occurs in discrete steps. Small, routine projects with no significant impacts are first screened out and allowed to proceed with a minimum loss of time and expense. Projects that may adversely affect the environment are submitted for a more detailed (and sometimes more visible and structured) review. Such projects could be subject to public review by an independent board or panel.

The Environmental Impact Statement (EIS) is used in most provinces and by the federal government to assess projects that may have a major adverse environmental impact. The EIS format is similar in all jurisdictions and involves (i) a project description, (ii) an analysis of how the project will affect the environment, and (iii) a description of proposed measures to reduce environmental impacts. It is normally prepared by the project proponent and is reviewed by the lead and other government agencies or by a public review board or panel.

The EIS process usually involves some form of public review, but the degree of formality varies among provinces, from formal legal procedures to informal community meetings. At both the federal and provincial levels, the final decision-maker is usually an elected official or officials -- a Cabinet minister or the entire Cabinet.

The processes in place in Canadian jurisdictions are outlined below. Some of this material is reviewed in more detail in a report prepared by the Canadian Council of Resources and Environment Ministers.[1] Since this 1985 report was completed, Manitoba, New Brunswick and Prince Edward Island have introduced major changes, and these are reflected in this chapter. In addition, an Environmental Assessment Act was passed in Nova Scotia in 1988 and was proclaimed in July 1989.

FEDERAL PROCESS

The Federal Government's Environmental Assessment Review Process

In December 1973, Cabinet established the federal Environmental Assessment Review Process (EARP) to ensure that the environmental effects of all federal proposals are assessed early in the planning process. A federal proposal is one initiated by a federal agency, or one that involves federal funding, federal property, or affects an area of federal responsibility. Federal Crown corporations are not bound by the Cabinet decision, but they are invited to participate in the process.

Under EARP, federal departments are responsible for assessing their own proposals. They conduct an initial screening to determine whether a given proposal will have significant environmental effects. If no such effects are perceived, the project may go ahead with appropriate monitoring by the initiating department. The results of all such decisions are published in summary form.

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[1] William J. Couch, Ph.D. (ed), *Environmental Assessment in Canada: 1985 Summary of Current Practice in Canada.* (Ottawa, Canadian Council of Resource and Environment Ministers, 1985, catalogue number EN 104-4/1985.)

If potentially significant environmental effects are perceived, a formal review process is undertaken by an Environmental Assessment Panel created by the Minister of the Environment. The Panel is assisted in its work by the Federal Environmental Assessment Review Office. The Panel normally requires that the sponsor of the proposal prepare an EIS. If the Minister of the Environment and the initiating minister concur, the scope of the Panel may be broadened to include general socioeconomic effects and the need for the project.

Public participation is an integral part of the assessment process. Any person or organization with an interest in the proposal is provided with an opportunity to appear before the Panel.

Once a Panel has completed its deliberations and evaluated all information on a proposal, it prepares a report containing its findings and recommendations. A Panel could recommend that a proposal not proceed, that it proceed as planned, or that it proceed subject to certain terms and conditions. The recommendations are submitted to the Minister of the Environment and the initiating minister, who must decide (i) to whom the recommendations are directed, (ii) to what extent they should be incorporated into terms and conditions governing the project, and (iii) in what manner they are to be made public. In the event of a disagreement between the two ministers, the question may be submitted to Cabinet.

Following the publication of a green paper in 1987 that identified a number of possible changes to the EARP process,[2] the Federal Environmental Assessment Review Office (FEARO) has carried out extensive consultations with the public, and federal departments and agencies. Bill C-78, introducing a new Canadian Environmental Assessment Act, was tabled in the House of Commons on June 18, 1990, and was discussed but not concluded in the last year's session. Bill C-78 was reintroduced as Bill C-13 in the House of Commons on May 29, 1991. Bill C-13 is now before the Senate at second reading and is expected to be passed in this fiscal year.

PROVINCIAL PROCESSES

British Columbia

The principal legal basis for British Columbia's energy project review process is the Utilities Commission Act, 1980. Major energy projects cannot proceed until the proponent has received approval by means of an Energy Project Certificate, a Ministers' Order, or a Certificate of Public Convenience and Necessity, all of which set out the terms and conditions under which the facility may be constructed and operated.

In order to obtain approval for a project, a proponent must provide a prospectus and then an application to the Ministry of Energy, Mines and Petroleum Resources, which in turn refers them to an Energy Project Coordinating Committee (EPCC). This steering group is chaired by the Ministry of Energy, Mines and Petroleum Resources, and includes representatives from the Ministry of Environment, the British Columbia Utilities Commission (BCUC), and FEARO.

In the application, the proponent must address, among other items, environmental impacts; impact management strategies; benefit and costs; and proposals for compensation, mitigation and monitoring. The EPCC, through three inter-ministry working groups, reviews the material and submits its recommendations to the ministers of Environment and Energy, Mines and Petroleum Resources. Generally, the recommendations are either for a public hearing by the BCUC or exemption from provisions of the Utilities Commission Act. The application may also be rejected if it fails to satisfy public interest criteria.

If an application is referred to the BCUC, once the public hearing is completed, a report is sent to the two ministers for consideration by Cabinet. The Minister of Energy, Mines and Petroleum Resources, with the concurrence of the Minister of Environment, then announces the Cabinet decision.

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[2] Environment Canada, *Reforming Environmental Assessment: A Discussion Paper.* (Ottawa, Minister of Supply and Services, Canada 1987, catalogue number EN 106-5/1987.)

If a public utility applies for an Energy Project Certificate, the ministers may refer the application to the BCUC for review and a decision. This may include holding a public hearing and may result in the issuance, directly by the Commission, of a Certificate of Public Convenience and Necessity.

Alberta

Alberta's Environmental Impact Assessment (EIA) process was established by the Land Surface Conservation and Reclamation Act of 1973. Pursuant to Section 8 of the Act, the Minister of the Environment may require the proponent of a proposed development to prepare an EIA report if he or she believes it is in the public interest to do so. The purpose of an EIA is to provide information to the public and the government to enable early identification and resolution of significant adverse effects on the environment.

The Alberta EIA process is implemented in accordance with the Alberta EIA Guidelines and administered by the Alberta Department of Environment. Most major resource developments proposed in Alberta are subject to this requirement. Major thermal and hydro generation projects require an EIA, and proponents of smaller projects must submit the environmental information necessary for the required approvals. In preparing an EIA, the proponent must consult with the public and provide opportunities for the public to participate in the preparation and review of the EIA.

Energy projects require the approval of the Alberta Energy Resources Conservation Board (ERCB) and Alberta Environment. Consequently, Alberta Environment and the ERCB coordinate their respective information requirements and reviews of energy projects. EIAs on energy projects are filed with Alberta Environment and the ERCB as part of the application to the ERCB. The ERCB may require a public hearing to be held for a project. After the ERCB makes its decision, Alberta Environment issues detailed environmental permits and licences.

The proposed Alberta Environmental Protection and Enhancement Act contains provisions for legislative environmental assessment in Alberta. This legislation is now before the Alberta Legislature and is expected to be passed during this fiscal year.

Saskatchewan

The Environment Assessment Act of 1980 requires environmental impact assessments to be completed for major development projects. Exemptions may be granted by Cabinet only in cases of emergency.

The province's environmental impact assessment and review process is administered by the Saskatchewan Department of Environment and Public Safety, and projects may proceed only with the approval of the Minister. Proposals are screened by the department to determine whether the Act applies to a project and, if so, the nature and scope of the EIA. If it is determined that an EIA is not required, the project may proceed subject to all other statutory requirements.

Where an EIA is required, proponents are encouraged to undertake a public participation program as early as possible so that public comments and recommendations may be considered during the preparation of the Environmental Impact Statement (EIS). Further safeguards are built into the process, such as a minimum 30-day public review of the EIS and the power given to the Minister to require a public information meeting to be conducted and/or appoint a board of inquiry. The final decision to approve (with or without conditions) or to refuse the proposed development rests with the Minister.

Manitoba

The Manitoba Environment Act of 1988 replaces the former Clean Environment Act of 1968 and the Environmental Assessment and Review Process, adopted as provincial Cabinet policy in 1975.

The Act ensures that any person or organization undertaking a development specified in the regulations is required to file a Proposal with the Department of

Environment at an early stage in the planning schedule. Other developments of environmental consequence are governed by regulations setting standards for environmental protection.

Developments are classified according to their potential environmental impact. Class 1 developments are any activities discharging pollutants. Class 2 developments are any activities with significant environmental impact caused by factors in addition to pollution, such as transportation and transmission facilities. Class 3 developments involve large-scale projects such as major hydroelectric developments.

Every submission for a development must be filed at a public registry. Once a proposal is filed, the Department of Environment is required to invite publicly written comments on the proposal. For more complex proposals, study guidelines are developed to assist proponents in preparing environmental assessments. Both the guidelines and the completed assessment are made available to the public for review.

Public meetings hosted by the proponent or public hearings by the Manitoba Clean Environment Commission, or both, may be held as part of the assessment and review process. The Commission's role is to provide advice and recommendations to the Minister and to develop and maintain public participation in environmental matters. The final product of the process is an environmental licence with terms and conditions specific to the proposal. Alternatively, a licence to proceed could be refused on the grounds of unacceptable environmental damage.

Ontario

The Minister of the Environment is responsible for the administration of the Environmental Assessment Act, which promotes improved planning by involving government ministries and agencies and the public in the environmental assessment, planning and approval process. (The environmental process in Ontario is also subject to the terms of the Consolidated Hearings Act, 1981. Details of the Consolidated Hearings Act may be obtained from *Environmental Assessment in Canada*[3], or from the October 1987 issue of *Canadian Environmental Law Reports*.[4]) The environmental assessment process in Ontario is currently being reviewed by the government. Amendments to the Environmental Assessment Act are expected to be proposed in the very near future.

The Environment Minister may, with the approval of Cabinet, exempt proponents from the application of the Environmental Assessment Act, which currently applies to the activities of provincial ministries, municipalities and conservation authorities. Only those projects of the private sector designated by regulation are subject to the Act. Proponents planning a project must determine if the Act applies; where it does not apply, or where an exemption has been granted, the activity may proceed. If the Act applies, the proponent must prepare an Environmental Assessment (EA), which is reviewed by the Ministry of Environment and other interested provincial and federal government organizations.

The Ministry subsequently prepares a Government Review which, together with the EA, is released for a minimum 30-day public review. A hearing of the Environmental Assessment Board may then be requested by the reviewers, the public or the proponent. The Minister -- with the concurrence of Cabinet -- will make a decision whether to accept the EA, and whether to approve the undertaking, with or without conditions. The Minister may refer the decision to accept the EA, or the decision to approve the undertaking, or both, to a Board hearing. When the Minister decides to refer the matter to a Board hearing, the Board must give reasonable notice of the hearing, which is open to the public. The Minister or Cabinet has 28 days to make any amendments to the Board's decision; if no amendments are made within this period, the Board's decision becomes binding.

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[3] William J. Couch, Ph.D., *op. cit.*

[4] *Canadian Environmental Law Reports*, New Series, Vol. 1, Part 6, October 1987.

Quebec

In Quebec, the process of environmental assessment varies depending on whether a project is in the south of the province or in a territory that is the subject of agreements with native people.

The 1972 Environment Quality Act was amended significantly in 1978 to include an environmental impact assessment and review procedure. By regulation, this procedure applies essentially to projects in the south of the province. When a project is subject to the procedure, the proponent must submit an EIA to the Department of the Environment for an admissibility analysis and an evaluation of the environmental acceptability of the project. All projects are subject to a public consultation period, during which any citizen may ask the Minister of the Environment to hold a public hearing. Citizens can thus voice their views before the project is referred to Cabinet for acceptance or refusal.

In the northern Quebec territories, the provincial government has implemented two procedures to assess and review the environmental and social impacts of a given project. The first procedure is applicable to the James Bay region (between the 49th and 55th parallels). A feature of this procedure is the use of committees on which native people are always represented. These committees advise the Minister of the Environment throughout the various stages of the authorization process. North of the 55th parallel, the Kativik Environmental Quality Commission is in charge of reviewing the impact assessment study and has decision-making authority. These procedures, which were incorporated into the Environment Quality Act, stemmed from the James Bay and Northern Quebec Agreement (1975) and the Northeastern Quebec Agreement (1978).

New Brunswick

New Brunswick's Regulation on Environmental Impact Assessment came into effect in July 1987, to provide a legislative framework for environmental planning, including opportunities for public involvement. The Regulation, which replaced the province's 1975 Policy on Environmental Assessment, is designed to identify the environmental impacts associated with development proposals, before their implementation.

Under the Regulation, individuals, companies or public agencies proposing certain types of projects (for example, all electric power generating facilities with a production rating of three MW or more, and all electric power transmission lines exceeding sixty-nine kV in capacity or five km in length) are required to register information about the project with the Minister of Environment, at an early stage in the planning cycle. The Minister then screens the proposal to determine whether it is likely to have significant environmental impacts, including socioeconomic and biophysical effects.

If it appears that the project's impacts are likely to be significant, the Minister will inform the proponent that an EIA is required, and staff from the Department of Environment will work with the proponent in preparing initial draft guidelines for the EIA Study. A Review Committee, consisting of technical specialists from government agencies potentially affected by the proposal, is appointed by the Minister to formulate draft guidelines for the Study. These draft guidelines, which identify the important environmental issues to be addressed, must then be issued by the Minister for public comment, and any interested party may provide written comments to the Minister.

The principal objective of the EIA Study is to predict the project's impacts, should it proceed. Information gathered during the study is compiled in a draft Environmental Impact Assessment Report, which is then carefully examined by the Review Committee. If, on the advice of the Committee, the Minister is satisfied that the report adequately addresses all aspects of the guidelines, a second and more comprehensive opportunity for public involvement begins. A summary of the report, comments of the Review Committee, and full copies of the final report are released for public review and comment.

A public meeting to discuss the EIA takes place. Thereafter, the Minister reviews the study and public comments, and then recommends to the Lieutenant-

Governor in Council whether or not the project should proceed.

Nova Scotia

The current legal basis for environmental impact assessment in Nova Scotia is the Environmental Assessment Act.

The Nova Scotia Department of the Environment (NSDOE), in consultation with other government agencies, is responsible for screening all projects submitted and advising the Minister on those that may have a significant and adverse environmental impact. After reviewing NSDOE's advice, as well as any public concern expressed, the Minister decides whether a project requires an Environmental Assessment (EA) Report. Where it is decided one is required, the proponent prepares a draft Report in response to guidelines and submits it to NSDOE. The department, other interested provincial and federal agencies, and the public review the EA Report. NSDOE then recommends to the Minister whether the project should be approved, with or without conditions, or refused.

The public is invited to participate in the review process by providing comments when a project is submitted to the NSDOE, when study guidelines are issued, and when the EA Report is released. The Minister, taking into consideration NSDOE's recommendations and the views of the public, decides whether the project should proceed and, if so, under what conditions.

Prince Edward Island

The Environmental Protection Act of 1988 provides the overall legal authority for the environmental assessment process. It requires that any person who wishes to initiate a project must file a written proposal with the Department of the Environment and obtain written approval from the Minister to proceed.

With respect to utilities, the process is set out in the Electric Power and Telephone Act, which authorizes the Public Utilities Commission to issue project-specific guidelines to the proponent for the preparation of an EIS, if it believes that the project may adversely affect the environment. A copy of the EIS is then sent by the Commission to the Executive Council for its consideration. The Council may make a decision on the evidence available, or it may determine that the public interest requires public hearings to be held in the locality affected by the project. After the public hearings, the Commission examines the evidence and issues its findings to the Executive Council.

Newfoundland

The province's environmental assessment process operates under the authority of the Environmental Assessment Act of 1980, which is administered by the Department of Environment and Lands.

Any project that may have a significant adverse environmental impact must be registered with the Minister of Environment and Lands. After public and interdepartmental reviews of the registration document, the Minister, on the advice of the department, decides whether or not an EIS is required. If an EIS is not required, the project may proceed subject to other relevant acts or regulations.

Where the Minister, on the advice of the Department, decides that an EIS may be required, an Environmental Preview Report (EPR) can be ordered. The EPR is prepared by the proponent and is available for public review and comment. Upon examination of the EPR, the Minister decides whether an EIS is required. If one is not required, the project may proceed subject to other relevant acts or regulations.

Where an EIS is required, it is prepared by the proponent; the Minister then makes it available for public review and comment. Should strong public interest be expressed, the Minister may recommend to Cabinet that an Environmental Assessment Board be appointed to conduct public hearings. The Minister makes the Board's report public, delivers copies to Cabinet, and subsequently recommends to Cabinet whether the project should be permitted to proceed, with or without conditions, or whether permission should be refused.

5. ELECTRICITY CONSUMPTION

ELECTRICITY AND PRIMARY AND SECONDARY ENERGY

Electricity constitutes a significant share of Canada's primary and secondary energy consumption. Primary energy refers to the amount of energy available to the final consumer, plus conversion losses and energy used by the energy supply industries themselves. (Conversion losses are losses in the processing of refined petroleum products, for example, or losses due to thermal and mechanical inefficiencies resulting from the conversion of fossil fuels -- coal, oil and natural gas -- into electricity in thermal-power generation.) The contribution of electricity to total primary energy consumption has steadily increased from 14 per cent in 1960 to 31 per cent in 1991, as shown in Figure 5.1. In terms of volume, primary energy consumption delivered in the form of electricity increased from 463 PJ in 1960 to 2501 PJ in 1991, an average annual growth of 5.6 per cent. This is more than double the average annual growth of non-electric primary energy consumption of 2.6 per cent registered for the same period (Since 1990, hydro has been converted at 3.6 rather than 10.5 megajoules per kilowatt hour for the primary energy form).

Secondary energy is the amount of energy available to, and used by, the consumer in its final form. Electricity constitutes a much smaller share of secondary energy consumption than primary energy consumption. Figure 5.2 indicates that electricity's share of Canadian secondary energy consumption was 11 per cent in 1960, and 24 per cent in 1991. The consumption growth rate for electricity was estimated to be 5.2 per cent during the period 1960-91, compared with non-electric secondary energy consumption of 2.1 per cent.

TOTAL ELECTRICITY CONSUMPTION

Total electricity consumption (i.e. demand) includes generation by electric utilities, generation by industrial establishments, and net imports (imports minus exports). As shown in Table 5.1, there have been two distinct periods in

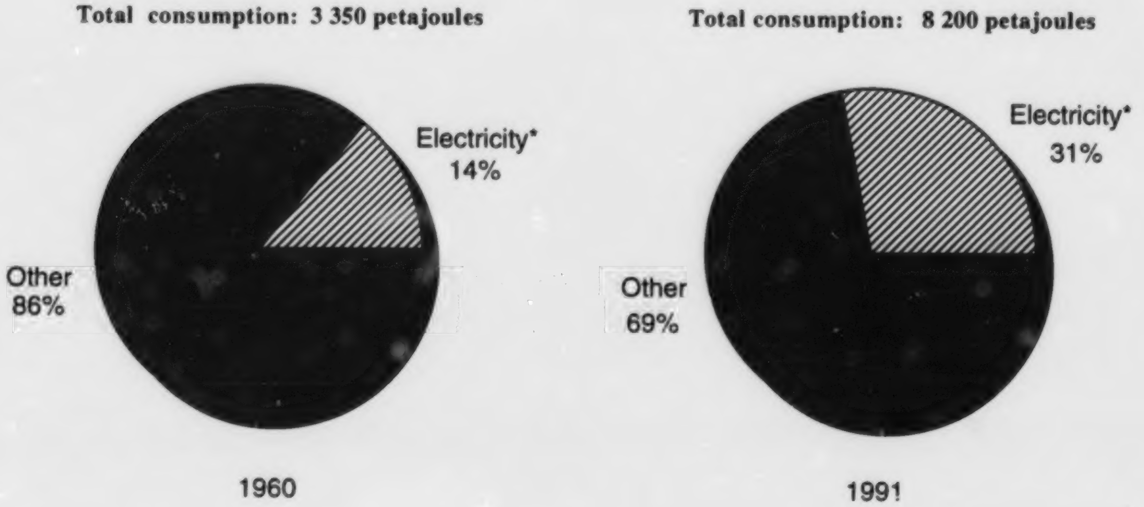
Table 5.1. Electricity consumption by province

	Electricity consumption (GW.h)					Average annual growth rate (per cent)			
	1960	1970	1980	1990	1991*	1960-74	1975-91	1960-91	1990-91
Nfld.	1 427	4 770	8 545	10 422	10 601	11.5	3.4	6.7	1.7
P.E.I.	79	250	518	753	762	11.9	3.8	7.6	1.2
N.S.	1 733	3 706	6 814	9 678	9 779	8.7	3.4	5.7	1.0
N.B.	1 684	4 221	8 838	13 173	13 638	10.1	4.5	7.0	3.5
Que.	44 002	69 730	118 254	157 308	160 803	5.4	3.7	4.3	2.2
Ont.	37 157	69 488	106 509	142 818	141 674	6.4	2.9	4.4	-0.8
Man.	4 021	8 601	13 927	17 450	18 013	7.9	2.6	5.0	3.2
Sask.	2 124	5 402	9 827	13 589	13 818	9.2	4.2	6.2	1.7
Alta.	3 472	9 880	23 172	42 041	43 338	10.7	6.7	8.5	3.1
B.C.	13 413	25 761	42 789	57 206	57 528	6.9	3.6	4.8	0.6
Yukon	89	220	381	485	465	9.3	1.8	5.5	-4.1
N.W.T.	100	308	494	472	477	10.2	0.7	5.2	1.1
Canada	109 304	202 337	340 068	465 395	470 895	6.6	3.6	4.8	1.2

** Preliminary Data*

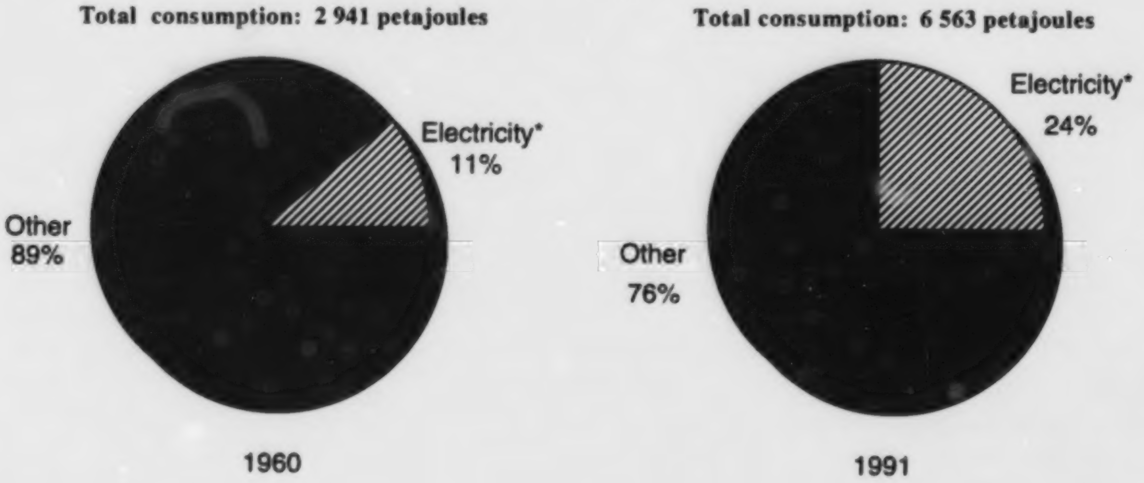
Source: Electric Power Statistics, Volume II, Statistics Canada, catalogue 57-202.

Figure 5.1. Primary energy consumption in Canada



**Converted at 3.6 megajoules per kilowatt hour.*

Figure 5.2. Secondary energy consumption in Canada



**Converted at 3.6 megajoules per kilowatt hour.*

electricity consumption growth over the past 31 years: the first period was one of high growth from 1960 to 1974, followed by a period of low growth from 1975 to 1991. The abrupt change coincided with the first oil embargo of 1973-74, following which consumption growth rates in the ten provinces and two territories shrunk significantly. This dramatic reduction in electricity demand growth was mainly attributed to reduced economic growth, high energy prices and energy conservation.

Overall, electricity consumption for Canada increased 1.2 per cent in 1991, despite economic recession. The real Gross Domestic Product experienced a negative growth of 1.5 per cent in 1991. Ontario was the only province that experienced consecutive negative electricity growth in 1990 and 1991. This occurred largely because of slow economic growth, mild weather and energy conservation efforts in the province.

Of the total electricity consumed in 1991, 39 per cent was consumed in the industrial sector, 30 per cent in the residential sector, 24 per cent in the commercial sector, and 7 per cent in transmission and distribution losses (Table 5.2). Although the market share of electricity consumption in the commercial sector was stabilized in 1991, its growth has been remarkable since 1960, averaging 7.3 per cent. Growth in the residential sector for the same period has averaged 6.4 per cent. The industrial sector has experienced the lowest growth, averaging 3.3 per cent from 1960 to 1991. In 1960, industrial consumption accounted for 60 per cent of total electricity consumption; since then it has gradually decreased and now appears to have stabilized around 40 per cent.

Table 5.2. Electricity consumption in Canada by sector

	Electricity consumption (GW.h)					Average annual growth rate (per cent)			
	1960	1970	1980	1990	1991*	1960-74	1975-91	1960-91	1990-91
Residential	20 397 (19)	43 431 (21)	92 440 (27)	137 001 (29)	139 733 (30)	7.9	5.0	6.4	2.0
Commercial	12 632 (12)	44 068 (22)	75 912 (21)	110 057 (24)	112 742 (24)	12.4	4.6	7.3	2.4
Industrial	66 353 (60)	98 450 (49)	142 247 (42)	184 136 (40)	183 911 (39)	4.3	2.7	3.3	-0.1
Line losses**	9 920 (9)	16 388 (8)	32 469 (10)	34 201 (7)	34 509 (7)	6.5	1.8	4.1	0.9
Total	109 304 (100)	202 337 (100)	340 068 (100)	465 395 (100)	470 895 (100)	6.6	3.6	4.8	1.2

** Preliminary data.*
*** Losses during transmission, distribution and unallocated energy.*
Figures in parentheses are percentage shares.

Source: Electric Power Statistics, Volume II, Statistics Canada, catalogue 57-202 and Energy, Mines and Resources Canada.

Table 5.3 shows electricity generation, trade and consumption for the provinces and territories in 1991. Quebec was the largest producing and consuming province, accounting for about 29 per cent of Canada's total production and about 34 per cent of total consumption. Ontario was second also with 29 per cent of production share and 30 per cent of consumption share. And British Columbia was in third place, with about 13 per cent in production and 12 per cent in consumption shares. Total electricity generation, consumption and net transfers are shown in Figure 5.3.

PER CAPITA ELECTRICITY CONSUMPTION

Table 5.4 reports per capita electricity consumption by province. As in the case of total consumption, per capita electricity consumption exhibited a high and low growth pattern before and after the oil crisis of 1973-74. For the period 1960-91, Saskatchewan had the highest growth rate of per capita electricity consumption, with an average of 6.9 per cent, followed by Prince Edward Island with 6.8 per cent, New Brunswick with 6.3 per cent, Alberta with 6.2 per cent, and Newfoundland with 5.8 per cent. High per capita electricity consumption in Saskatchewan was mainly attributed to a low growth of population in the province. During the past 31 years, population in Saskatchewan grew an average of only 0.3 per cent, the lowest in Canada compared to a national average of 1.3 per cent.

In 1991, Quebec was the largest electricity user in Canada with 23 489 kW.h per person, despite its negative per capita consumption growth rate, while Prince Edward Island was the smallest with 5817 kW.h per person. Quebec's per capita consumption was 35 per cent above the national average, while P.E.I. was 67 per cent below the average.

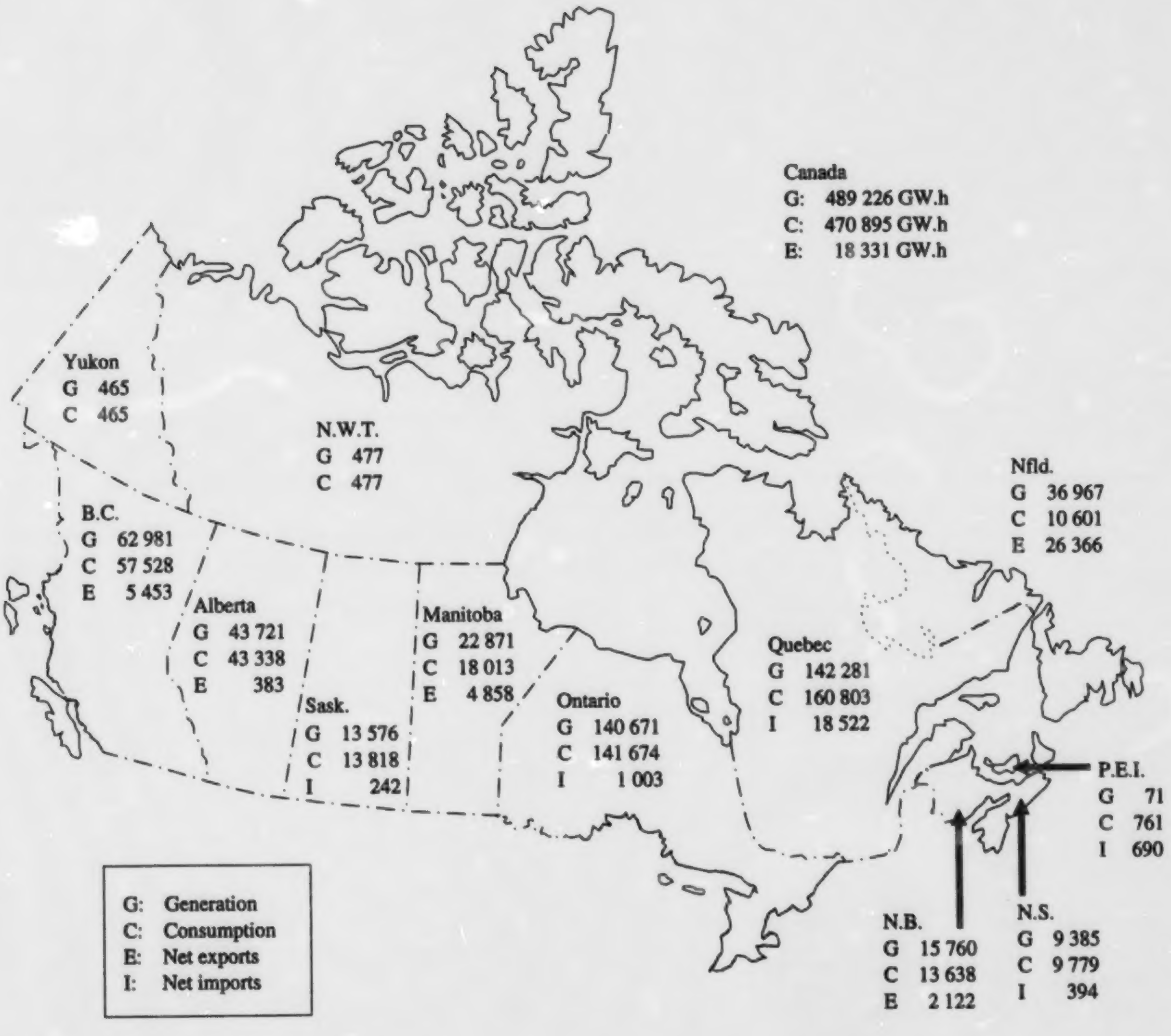
Table 5.3. Provincial electricity consumption and generation, 1991

		Exports to		Imports from		
	Generation	Provinces	U.S.A.*	Provinces	U.S.A*	Consumption
			(GW.h)			
Nfld.	36 967	26 366	0	0	0	10 601
P.E.I.	71	0	0	690	0	761
N.S.	9 385	50	0	444	0	9 779
N.B.	15 760	2 542	3 092	3 433	79	13 638
Que.	142 281	4 112	6 054	27 883	805	160 803
Ont.	140 671	109	4 771	2 210	3 673	141 674
Man.	22 871	2 634	3 488	975	289	18 013
Sask.	13 576	998	139	12 619	110	13 818
Alta.	43 721	1 064	0	678	3	43 338
B.C.	62 981	655	7 070	948	1 324	57 528
Yukon	465	0	0	0	0	465
N.W.T.	477	0	0	0	0	477
Canada	489 226	38 530	24 614	38 530	6 283	470 895

** Service exchange is included.*

Source: Energy, Mines and Resources Canada.

Figure 5.3. Electricity generation, consumption and net transfers, 1991 (GW.h)


Canada
G: 489 226 GW.h
C: 470 895 GW.h
E: 18 331 GW.h
Yukon
G 465
C 465
N.W.T.
G 477
C 477
B.C.
G 62 981
C 57 528
E 5 453
Alberta
G 43 721
C 43 338
E 383
Sask.
G 13 576
C 13 818
I 242
Manitoba
G 22 871
C 18 013
E 4 858
Ontario
G 140 671
C 141 674
I 1 003
Quebec
G 142 281
C 160 803
I 18 522
Nfld.
G 36 967
C 10 601
E 26 366
P.E.I.
G 71
C 761
I 690
N.B.
G 15 760
C 13 638
E 2 122
N.S.
G 9 385
C 9 779
I 394
G: Generation
C: Consumption
E: Net exports
I: Net imports

HOUSEHOLD CHARACTERISTICS AND FACILITIES

As noted earlier, electricity consumption in the residential sector has steadily increased. In addition to economic factors, changes in household characteristics and household facilities and equipment also have considerable impact on residential electricity consumption. Table 5.5 summarizes household characteristics and facilities by province for 1991.

During the past 16 years, the number of households in Canada has increased from 6.9 million in 1976 to about 9.9 million in 1991, a net increase of 3 million. However, the average number of persons per household has declined from 3.15 to 2.64 persons per household in the same period.

The use of electricity for space heating, mainly in the province of Quebec, has steadily increased from 13 per cent of total households in 1976 to 34 per cent by 1991; the number of air conditioners from 13 per cent to 27 per cent; automatic dishwashers from 19 per cent to 44 per cent; and the use of electricity for hot water increased slowly from 50 per cent in 1976 to 53 per cent in 1991. The use of electric washing machines also increased slightly in the same period, from 76 per cent to 78 per cent, while the use of electric clothes dryers increased significantly from 51 per cent to 73 per cent. By the end of 1991, households equipped with refrigerators and colour TV sets in Canada almost reached 100 per cent.

ECONOMIC GROWTH AND ELECTRICITY CONSUMPTION

Electricity consumption is affected by many factors: economic activity, demographic variables, electricity prices, other energy prices, conservation, policy changes, technological changes and weather. However, aggregate economic activity (as measured by the GDP) is the most important variable. The historical relationship between per capita GDP and per capita electricity consumption is shown in Figure 5.4. Although the historical relationship between national economic growth and electricity consumption was dislocated between 1979 and 1983, it has reappeared since 1984.

Table 5.4. Per capita electricity consumption by province

	Per capita consumption (kW.h/person)					Average annual growth rate (per cent)			
	1960	1970	1980	1990	1991	1960-74	1975-91	1960-91	1990-91
Nfld.	3 184	9 226	14 758	18 188	18 469	10.1	3.1	5.8	1.5
P.E.I.	765	2 273	4 177	5 748	5 817	11.1	3.0	6.8	1.2
N.S.	2 385	4 739	7 988	10 813	10 853	7.9	2.8	5.0	0.4
N.B.	2 864	6 732	14 850	18 245	18 785	9.2	4.0	6.3	3.0
Que.	8 565	11 597	18 735	23 556	23 489	4.1	3.0	3.3	-0.3
Ont.	6 086	9 203	12 422	14 648	14 290	4.3	1.7	2.8	-2.4
Man.	4 932	8 750	13 521	16 024	16 480	6.3	2.1	4.0	2.8
Sask.	1 750	5 741	10 131	13 630	13 901	11.6	3.6	6.9	2.0
Alta.	2 695	6 194	11 135	17 000	17 184	8.4	4.4	6.2	1.1
B.C.	8 386	12 124	16 220	18 259	17 871	3.9	1.8	2.5	-2.1
Yukon	4 589	11 957	17 085	18 654	17 222	8.7	0.2	4.4	-7.7
N.W.T.	5 304	8 851	11 052	8 741	8 673	3.5	-1.1	1.6	-0.8
Canada	6 184	9 501	13 112	17 490	17 441	4.9	2.5	3.4	-0.3

Source: Electricity Branch, Energy, Mines and Resources Canada.

PEAK DEMAND

Peak demand is the annual maximum average net kilowatt load of one hour duration within an electrical system. For Canada as a whole, as shown in Table 5.6, peak demand grew from 17 264 MW in 1960 to 82 863 MW in 1991, an average annual growth rate of 5.2 per cent[1]. In comparison, total electricity consumption during the same period grew at an average annual rate of 4.8 per cent. In 1991, like energy demand, peak demand also experienced a slow growth of 1.9 per cent because of warm weather and economic recession.

(Before 1987, *Electric Power in Canada* reported peak demand for the calendar year. However, beginning in 1987, calendar-year peak was replaced by winter peak -- November to February. This change was made in order to make our reporting period consistent with that of the utilities.)

LOAD FACTOR

Load factor is defined as the ratio of average demand to peak demand in any given period. More precisely, it is the energy demand in kilowatt hours divided by the product of the number of hours in the period, multiplied by the peak demand in kilowatts. (In a year-base, average demand equals annual energy consumption divided by 8760 hours per year.)

Table 5.7 shows that for the electric power industry in Canada, as a whole, load factor has declined since 1960. This has occurred because peak demand has grown faster than energy demand (5.2 per cent compared with 4.8 per cent). In 1960, the industry load factor was 72.3 per cent, but by 1985 it had gradually been reduced to 65.1 per cent. It was up slightly to 67.8 per cent in 1988, dropped again in 1990 to 65.3 per cent, and declined further to 64.9 per cent in 1991. Since 1960, those provinces with thermal-based generation (Saskatchewan and Alberta) have all shown improvements in their load factors.

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[1] Peak demand for Canada as a whole is the non-coincident peak, i.e. the arithmetic sum of the provincial peaks regardless of the time of occurence.

Table 5.5. Household characteristics and facilities in Canada, 1991

	Canada	Nfld.	P.E.I.	N.S.	N.B.	Que.	Ont.	Man.	Sask.	Alta.	B.C.
Total Number of households (1 000)	9 873	177	47	326	251	2 618	3 585	389	359	898	1 225
Average persons per household	2.6	3.2	2.7	2.7	2.8	2.5	2.7	2.6	2.6	2.7	2.5
Single dwellings*(%)	68	87	79	78	82	52	69	77	83	79	73
Electricity for space heating (%)	34	43	-	26	55	67	22	33	5	3	24
Air conditioners (%)	27	-	-	4	6	15	48	45	32	10	9
Electricity for hot water (%)	53	85	22	60	88	87	43	47	25	8	44
Electricity for cooking (%)	94	96	81	89	96	98	92	98	96	92	93
Microwave ovens (%)	74	65	64	72	73	71	74	75	79	80	74
Refrigerators (%)	100	99	96	99	99	100	100	100	100	100	99
Freezers (%)	58	77	62	60	69	47	58	72	80	67	60
Automatic dishwashers (%)	44	22	26	31	32	46	41	40	47	55	50
Electric washing machines (%)	78	92	81	79	88	85	73	77	84	81	74
Electric clothes dryers (%)	73	75	66	70	80	78	69	73	81	79	71
Colour TV sets (%)	97	97	96	97	97	97	98	96	97	97	98

**Including mobile homes.*

Source: Household Facilities and Equipment, Statistics Canada, catalogue 64-202.

Table 5.6. Peak demand by province

	Peak Demand (MW)					Average annual growth rate (per cent)	
	1960	1970	1980	1990	1991*	1960-91	1990-91
Nfld.	245	763	1 538	1 848	1 852	6.7	0.2
P.E.I.	21	55	104	135	137	6.2	1.5
N.S.	356	814	1 197	1 825	1 887	5.5	3.4
N.B.	319	726	1 699	2 627	2 757	7.2	5.0
Que.	5 871	11 127	20 680	29 259	29 357	5.3	0.3
Ont.	6 391	12 048	17 767	23 752	24 489	4.4	3.1
Man.	772	1 565	2 681	3 524	3 809	5.3	8.1
Sask.	418	1 028	2 085	2 356	2 371	5.8	0.6
Alta.	714	1 894	3 879	6 509	6 515	7.4	0.1
B.C.	2 123	4 492	7 384	9 329	9 492	5.0	1.7
Yukon	19	39	75	81	82	4.8	1.2
N.W.T.	15	41	81	107	115	6.8	7.5
Canada	17 264	34 592	59 170	81 352	82 863	5.2	1.9

** Preliminary data*

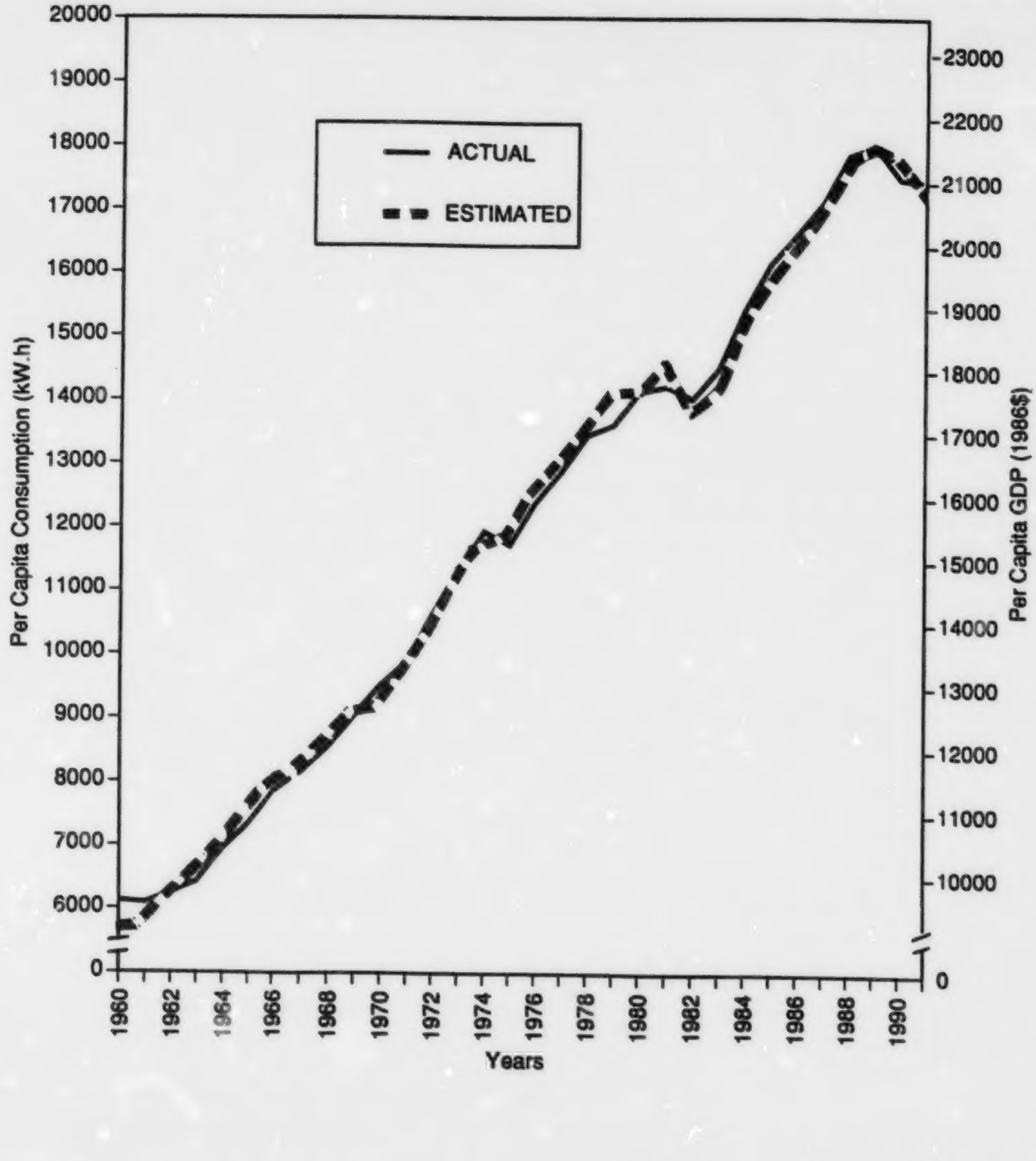
Source: Electric Power Statistics, Volume I, Statistics Canada, catalogue 57-204.

Table 5.7. Load factor by province

	1960	1965	1970	1975	1980	1985	1990	1991
	(per cent)							
Nfld.	66.5	72.6	71.4	68.7	65.3	64.5	64.4	65.3
P.E.I.	66.4	65.4	65.8	65.4	68.4	64.9	63.7	63.5
N.S.	59.5	66.4	62.7	58.4	59.3	62.0	60.5	59.2
N.B.	58.0	60.3	60.0	62.2	53.8	62.5	57.2	56.5
Que.	85.6	72.5	71.5	67.9	65.3	64.5	61.4	62.5
Ont.	66.4	65.4	65.8	65.4	68.4	64.9	68.6	66.0
Man.	59.5	66.4	62.7	58.4	59.3	62.0	56.5	54.0
Sask.	58.0	60.3	60.0	62.2	53.8	62.5	65.8	66.5
Alta.	55.5	57.1	59.6	64.2	68.2	72.3	73.7	75.9
B.C.	72.1	71.6	65.5	64.4	66.2	66.1	70.0	69.2
Yukon	53.5	77.8	64.4	60.9	58.0	54.3	68.4	64.7
N.W.T.	76.1	58.6	85.8	71.3	69.6	70.6	50.4	47.3
Canada	72.3	68.1	66.8	65.7	65.6	65.1	65.3	64.9

Source: Calculated from Tables 5.1 and 5.6

Figure 5.4. Historical relationship between electricity demand and GDP, 1960-1991



6. ELECTRICITY GENERATION

SOURCES OF GENERATION

Canada's electric power industry began in the 1880s with electricity generated by steam. In the beginning, electricity was used mainly for home and street lighting. In the late-1880s and 1890s, the invention of the electric motor dramatically changed the industry from one that mainly provided nighttime power for lighting to one that also provided power for transportation and industry needs 24 hours a day. Following this development, the use of hydroelectricity spread rapidly due to Canada's abundant water resources. In 1920, hydro accounted for more than 97 per cent of total electricity production in Canada. This percentage declined slightly to 95 per cent by 1950, and 92 per cent by the end of 1960. By 1991, hydro production had further declined to about 62 per cent (Table 6.1 and Figure 6.2).

Thermal generation, mainly from coal-fired stations, has been a part of Canada's generation mix since the beginning of the electric power industry, although for many years its share of total production did not increase significantly because of its relatively high cost of production. By the 1960s and 1970s, however, when most of Canada's economical hydro sites had been developed, the situation changed and thermal generation became competitive.

Between 1950 and 1974, the growth rate of real fossil-fuel prices (coal, oil and natural gas) was negative -- a situation that led most electric utilities to build more thermal stations. As Table 6.1 indicates, thermal generation accounted for only 7 per cent of the total generated electricity in 1960. However, its production share jumped to 23 per cent by 1970, and reached a peak of 25 per cent in 1974. After the first oil crisis of 1973-74, fossil-fuel prices increased substantially, averaging more than 15 per cent during the period 1975-85. As a result, the share of thermal production gradually declined to 22 per cent by 1980, and 20 per cent by 1985. With the collapse of oil prices in 1986, thermal generation once again became economical, resulting in an increase in the share of thermal production to 22 per cent in 1990, and 21 per cent in 1991.

The production of nuclear power began in Canada in 1962 when the

Table 6.1. Sources of electricity generation

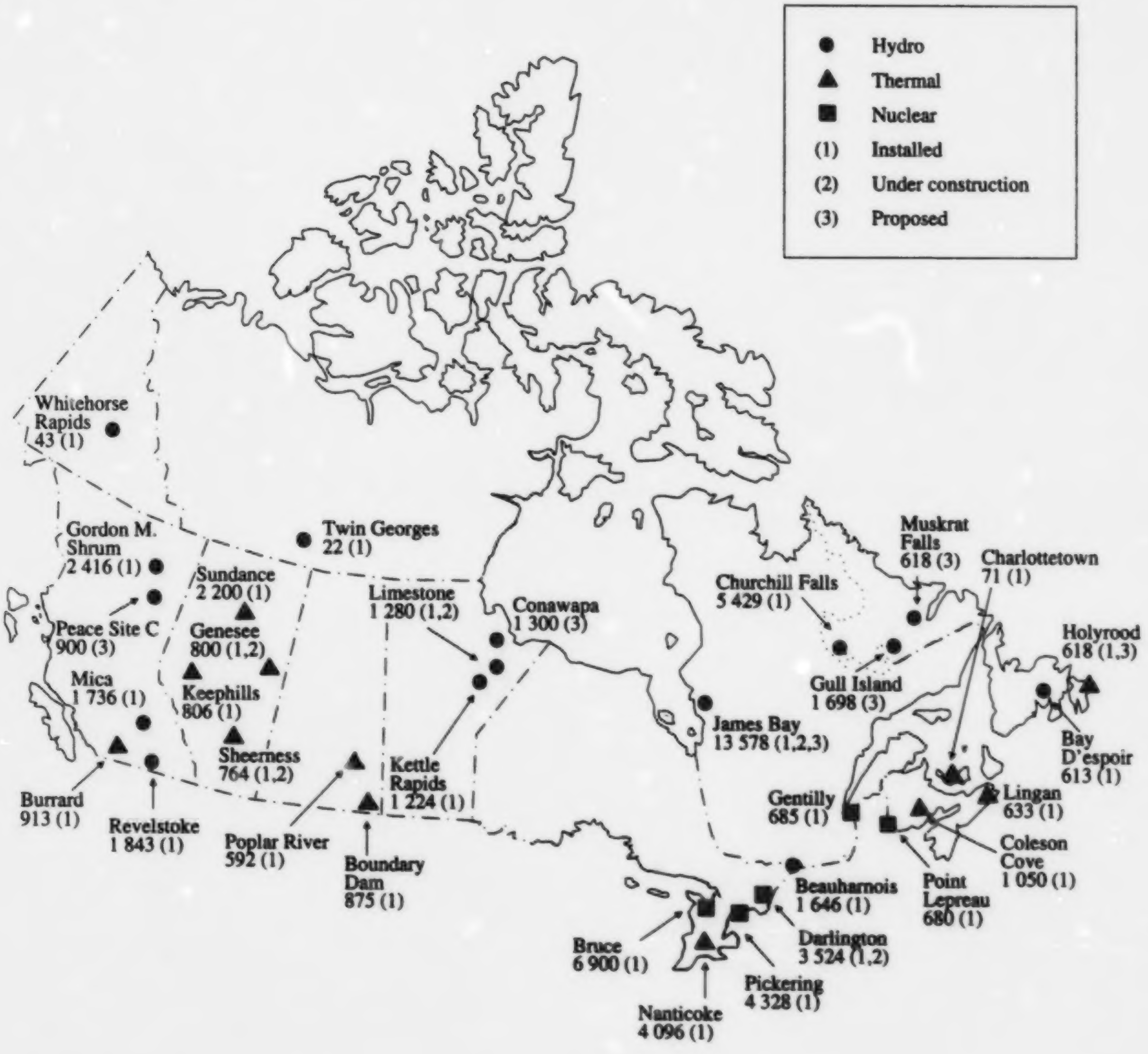
	Electricity Generation					Average Annual Growth Rate	
Fuel Type	1960	1970	1980	1990	1991	1960-1991	1990-1991
			(GW.h)			(per cent)	
Hydro	105 883	156 709	251 217	292 810	304 296	3.5	3.9
Thermal	8 495	47 045	80 207	104 121	104 776	8.4	0.6
Nuclear*	-	969	35 882	68 837	80 123	-	16.4
Tidal**	-	-	-	26	32	-	23.1
Total	114 378	204 723	367 306	465 744	489 227	4.8	5.0

** Commercial operation started in 1968.*

*** Commercial operation started in 1984.*

Source: Electric Power Statistics, Volume (II), Statistics Canada, catalogue 57-202, and Electric Power Statistics Monthly, Statistics Canada, catalogue 57-001.

Figure 6.1. Major generating stations by province, 1991 (MW).


● Hydro
▲ Thermal
■ Nuclear
(1) Installed
(2) Under construction
(3) Proposed
Whitehorse Rapids 43 (1)
Gordon M. Shrum 2 416 (1)
Twin Georges 22 (1)
Sundance 2 200 (1)
Peace Site C 900 (3)
Genesee 800 (1,2)
Mica 1 736 (1)
Keephills 806 (1)
Sheerness 764 (1,2)
Burrard 913 (1)
Revelstoke 1 843 (1)
Poplar River 592 (1)
Boundary Dam 875 (1)
Limestone 1 280 (1,2)
Conawapa 1 300 (3)
Kettle Rapids 1 224 (1)
Churchill Falls 5 429 (1)
Muskrat Falls 618 (3)
Charlottetown 71 (1)
Gull Island 1 698 (3)
Holyrood 618 (1,3)
James Bay 13 578 (1,2,3)
Bay D'espoir 613 (1)
Gentilly 685 (1)
Lingan 633 (1)
Coleson Cove 1 050 (1)
Point Lepreau 680 (1)
Beauharnois 1 646 (1)
Darlington 3 524 (1,2)
Bruce 6 900 (1)
Pickering 4 328 (1)
Nanticoke 4 096 (1)

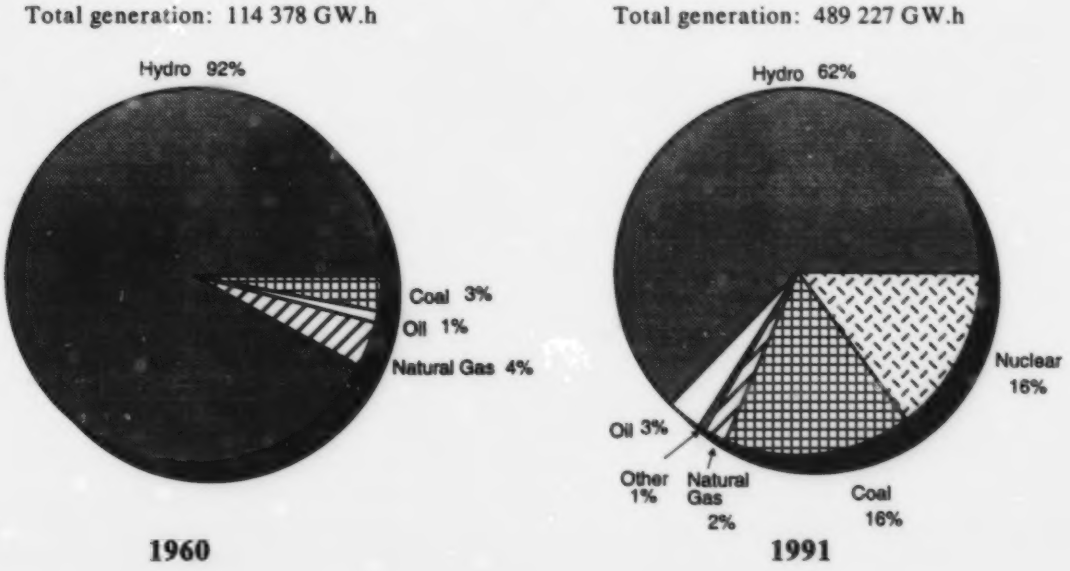
25-MW Rolphton station went into operation. In 1968, commercial operation started at the 220-MW Douglas Point station in Ontario, owned by Atomic Energy of Canada Ltd. During the 1970s, nuclear production emerged as an important source of electricity in Canada, and by 1975 nuclear generation accounted for more than 4 per cent of total electricity production. Most of the nuclear generation came from the first four Pickering stations in Ontario, which were completed between 1971-73. By 1980, the nuclear production share increased to about 10 per cent of Canada's total, with the completion of four of Ontario's Bruce stations.

By 1985, nuclear generation accounted for 13 per cent of Canada's total generated electricity. Between 1980 and 1985, seven nuclear stations were brought into service: Gentilly 2 in Quebec; Point Lepreau in New Brunswick; Pickering stations 5, 6 and 7, and Bruce stations 5 and 6, all located in Ontario. By 1991, the nuclear generation share had increased to about 16 per cent with the commissioning of Pickering 8, Bruce 7 and 8, and Darlington 2, all of which went into operation in 1986, 1987, and 1990.

To date, tidal power has played an insignificant role in electricity generation in Canada. However, it is worth noting that the 20-MW Annapolis tidal power plant in Nova Scotia, which began operation in 1984, is the first of its kind in North America. Although the plant requires a high level of maintenance, compared with conventional hydro plants, it has operated without any major difficulties since 1984.

Electricity generation increased by 5 per cent in 1991, to 489 227 GW.h after two consecutive years in which electricity generation had declined in Canada. The increase is mainly attributed to a greater number of exports to the United States and stronger domestic demand in New Brunswick, Quebec, Manitoba, and Alberta. Of the total electricity generated in 1991, 464 613 GW.h was for use in Canada, and the remaining 24 614 GW.h was exported. The sources of generation are given in Table 6.1, and the major generating stations in each province are shown in Figure 6.1.

Figure 6.2. Electricity generation by fuel type



Between 1960 and 1991, the share of hydro production dropped from 92 per cent to 62 per cent, as shown in Figure 6.2. The natural gas production share also decreased (from 4 per cent in 1960 to 2 per cent in 1991), while the oil share increased (from 1 per cent to 3 per cent over the same period). With the first oil crisis of 1973-74, electric utilities were discouraged from using natural gas and oil for baseload electricity generation. However, as noted above, the collapse of oil prices in 1986 has made electricity generation from oil more economical.

Nuclear production has had the largest gain in production share, moving from zero in 1960 to about 16 per cent by 1991, while the coal production share increased from 3 per cent to 16 per cent over the same period. These increases have occurred at the expense of hydro. With the relatively cheap fuel prices of uranium and coal, and the development of most of the country's economical hydro sites, hydro's production share has declined significantly since 1960.

Electrical energy production by fuel type in 1991 is reported in Table 6.2. In Newfoundland, Quebec, Manitoba, and British Columbia, hydro generation accounted for more than 94 per cent of the total. In Alberta, about 82 per cent of total generation came from coal. Coal generation was also important in Saskatchewan and Nova Scotia, at 64 per cent and 60 per cent respectively. In Ontario, coal, nuclear and hydro production are well balanced, while in New Brunswick, total generation is a mix of oil, nuclear, hydro and coal.

Ontario, Quebec and New Brunswick are the only three provinces that produce nuclear energy in Canada. In 1991, nuclear generation accounted for 46 per cent of Ontario's total electricity generation, 32 per cent of New Brunswick's, and 3 per cent of Quebec's. Electricity

Table 6.2. Electrical energy production by fuel type, 1991

	Coal	Oil	Natural Gas	Nuclear	Hydro	Other	Total
				(GW.h)			
Nfld.	0	1 523	0	0	35 445	0	36 968
P.E.I.*	0	71	0	0	0	0	71
N.S.	5 855	2 353	0	0	1 034	143	9 385
N.B.	1 150	5 937	0	5 440	2 971	261	15 759
Quebec	0	504	0	3 910	137 867	0	142 281
Ontario	29 268	1 096	1 876	70 773	37 418	240	140 671
Manitoba	265	20	13	0	22 543	30	22 871
Sask.	8 644	18	533	0	4 205	176	13 576
Alberta	36 836	0	4 181	0	2 030	674	43 721
B.C.	0	550	1 201	0	60 149	1 081	62 981
Yukon	0	55	0	0	410	0	465
N.W.T.	0	222	0	0	256	0	478
Canada	82 018	12 349	7 804	80 123	304 328	2 605	489 227

** PEI has 10 per cent ownership in New Brunswick's Dalhousie coal-fired station, unit 2.*

Source: Energy, Mines and Resources Canada generation from natural gas occurs mainly in industries that generate power for their own use. In all provinces except Newfoundland, Nova Scotia and New Brunswick, oil is used mainly for peaking purposes.

GENERATION BY PROVINCE

Table 6.3 shows electricity generation by province during the period 1960-91, and generation growth rates for 1991 over 1990 and the period 1960-91. Newfoundland had the greatest production growth during the period 1960-91, with an average growth rate of 10.9 per cent. This was due mainly to the completion of the Churchill Falls hydro station (5 429 MW) in Labrador in 1974. Over 90 per cent of the electricity produced at Churchill Falls flows into Quebec under a contract that ends in the year 2041.

Electricity generation fluctuated significantly in Prince Edward Island during the period 1960-91. The province's electrical generating plants are relatively small, are fuelled by oil, and are consequently expensive to operate. In 1977, an interprovincial interconnection was completed, allowing P.E.I. to purchase electrical energy from New Brunswick. In addition, in 1981, P.E.I. purchased a 10 per cent ownership interest in the 200-MW coal/oil-fired plant at Dalhousie, New Brunswick. Because of the interconnection and joint ownership, P.E.I. has been able to reduce the amount of generation from its own oil-fired stations.

In 1991, there was negative growth in electricity generation in Prince Edward Island, Nova Scotia, New Brunswick, and the Yukon (Table 6.3). However, Manitoba had a substantial increase, which was attributed to the addition of four new units at the Limestone hydroelectric project.

Figure 6.3 presents electricity generation by region. Although

Table 6.3. Electricity generation by province

	Electricity Generation					Average Annual Growth Rate	
	1960	1970	1980	1990	1991	1960-1991	1990-1991
			(GW.h)			(per cent)	
Nfld.	1 512	4 854	46 374	36 585	36 968	10.9	1.1
P.E.I.	79	250	127	81	71	-0.3	-12.3
N.S.	1 814	3 511	6 868	9 430	9 385	5.4	-0.5
N.B.	1 738	5 142	9 323	16 665	15 759	7.4	-5.4
Quebec	50 433	75 877	97 917	135 458	142 281	3.4	5.0
Ontario	35 815	63 857	110 283	129 343	140 671	4.5	8.8
Manitoba	3 742	8 449	19 468	20 149	22 871	6.0	13.5
Sask.	2 204	6 011	9 204	13 540	13 576	6.0	0.3
Alberta	3 443	10 035	23 451	42 874	43 721	8.5	2.0
B.C.	13 409	26 209	43 416	60 662	62 981	5.1	3.8
Yukon	89	224	381	485	465	5.5	-4.1
N.W.T.	100	304	494	472	478	5.2	1.3
Canada	114 378	204 723	367 306	464 744	489 227	4.8	5.3

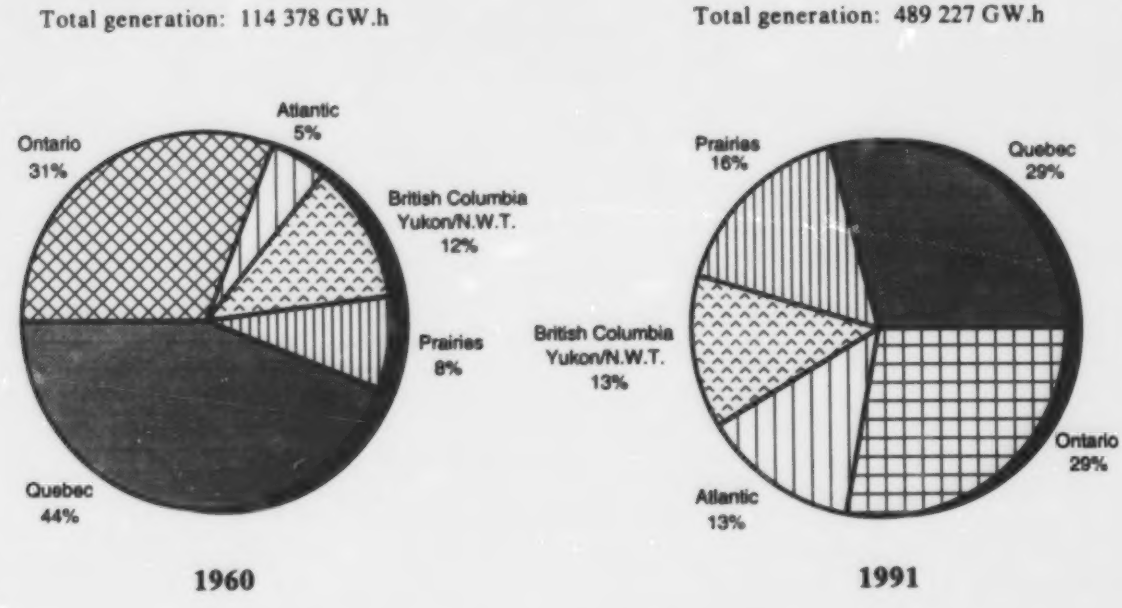
Source: Electric Power Statistics, Volume (II), Statistics Canada, catalogue 57-202.

Table 6.4. Fuels used to generate electricity in Canada

	1960	1965	1970	1975	1980	1985	1988	1989	1990	1991
Coal (10^3 tonnes)	1 674	7 004	13 786	16 567	27 785	39 456	45 975	47 341	41 822	45 313
Oil (10^3 cubic metres)	328	871	1 869	2 309	2 867	1 391	2 615	4 410	3 888	3 161
Natural Gas (10^6 cubic metres)	1 069	1 679	1 992	4 009	1 875	1 223	3 628	5 247	3 084	2 239
Uranium (tonnes)	0	2	16	194	685	1 086	1 358	1 284	1 386	1 517

Source: Electric Power Statistics, Volume (II), Statistics Canada, catalogue 57-202, and Energy, Mines and Resources Canada.

Figure 6.3. Electricity generation by region



Total generation: 114 378 GW.h

1960

Total generation: 489 227 GW.h

1991

Quebec has been the largest electricity producer in Canada since 1960, its share has declined from 44 per cent in 1960 to 29 per cent in 1991. Ontario was the second-largest producer, also with 29 per cent in 1991, compared with 31 per cent in 1960. British Columbia has remained the third largest electricity producer over the period, generally providing 13 per cent of the total. Electricity generation growth rates for Newfoundland, Nova Scotia, New Brunswick, Manitoba, Saskatchewan and Alberta were all greater than those for Quebec, Ontario and British Columbia during 1960-91. This indicates that generation shares for the Atlantic and Prairie provinces are increasing at the expense of the top three provinces.

FOSSIL-FUEL REQUIREMENTS

Because of the rapid expansion of coal-fired stations in the 1960s and 1970s, coal consumption increased about tenfold during the period 1960-75, and more than doubled in the following ten years. However, in recent years, because of environmental concerns, the amount of coal used to generate electricity has not increased as fast as before.

The use of natural gas and oil for electricity generation peaked in the mid-1970s and 1980, and then declined sharply. However, with the collapse of international oil prices in 1986, the situation reversed itself and it again became economical for electric utilities to use oil and natural gas for electricity generation (Table 6.4). The use of uranium has increased dramatically since 1970 with the growth of nuclear capacity in Canada, particularly in Ontario.

In 1991, provinces west of Quebec continued to use Canadian oil, primarily light oil and diesel oil, in gas turbines or diesel plants. In the Yukon and Northwest territories, Canadian diesel oil was used to supply

Table 6.5. Fuels used to generate electricity by province, 1991

	Coal (10^3 tonnes)	Oil (cubic metres)	Gas (10^6 cubic metres)	Uranium (tonnes)
Nfld.	0	383 000	0	0
P.E.I.	40	28 000	0	0
N.S.	2 290	566 000	0	0
N.B.	427	1 511 000	0	102
Quebec	0	177 594	0	74
Ontario	12 010	297 000	546	1 341
Manitoba	153	3 000	3	0
Sask.	7 555	3 500	149	0
Alberta	22 838	0	1 276	0
B.C.	0	106 000	265	0
Yukon	0	15 096	0	0
N.W.T.	0	71 000	0	0
Canada	45 313	3 161 190	2 239	1 517

Note: 1 cubic metre oil = 6.3 barrels; 1 barrel of oil is defined as 5 800 000/BTU.
1 cubic metre gas = 35.5 cubic feet; 1 cubic foot of natural gas is defined as 1000 BTU.
1 tonne = 1000 kilograms; 1 gram of uranium is defined as 603 825 BTU.

Source: Energy, Mines and Resources Canada.

electricity to small remote communities. Oil used by the Atlantic region and Quebec was imported.

In 1991, about 68 per cent of the coal used for electricity generation in Ontario was imported from the United States, while the remainder came from western Canada. Coal used by Manitoba was purchased from Saskatchewan, while Alberta, Nova Scotia and New Brunswick used their own coal resources. Saskatchewan relied primarily on its own coal, but also purchased additional amounts from Alberta.

EMISSIONS FROM ELECTRICITY GENERATION

As shown in Table 6.1, 104 776 GW.h of electricity came from conventional thermal sources, which accounted for about 21 per cent of total electricity generated in 1991. This amount of thermal generation required a considerable quantity of fossil fuels: 45 million tonnes of coal; 3.2 million cubic metres of oil; and 2239 million cubic metres of natural gas (Table 6.5).

The combustion of fossil fuels can produce carbon dioxide, sulphur dioxide, nitrous oxides, etc. Emissions from electricity generation in 1991 are presented in Table 6.6.

Table 6.6. Emissions from electricity generation, 1991

	SO_2 (1000 tonnes)	NO_x (1000 tonnes)	CO_2 (1000 tonnes)
Newfoundland	16	3	1 204
Prince Edward Island	1	0	82
Nova Scotia	141	28	6 850
New Brunswick	150	21	5 250
Quebec	4	0	0
Ontario	167	56	27 900
Manitoba	2	2	426
Saskatchewan	77	34	10 363
Alberta	116	84	41 313
British Columbia	0	0	0
Yukon	0	0	0
Northwest Territories	0	0	66
Electric Utilities' Total	674	228	93 454
Canada's Total Resulting from Energy Activities	1 070	1 690	429 000
Electric Utilities' Share (%)	63	14	22

Source: Electric Utilities and Energy, Mines and Resources Canada

7. GENERATING CAPACITY AND RESERVE

As noted in Chapter 6, Canada's first electrical generating stations were thermal. As the demand for electricity grew, however, hydroelectric power quickly proved to be more economical than thermal. In 1920, hydro accounted for 86 per cent of total generating capacity, and by 1945, hydro's share of total installed capacity peaked at 94 per cent. Since then, the capacity share of hydro has declined gradually, reaching about 81 per cent by 1960 and 58 per cent by 1991 (Table 7.1).

Several factors have contributed to the gradual reduction in the capacity share of hydro since the end of World War II. By 1945, most of Canada's economic hydro sites had been developed. Moreover, the growth rates of real fossil-fuel prices (coal, oil and natural gas) were negative between 1950 and 1974, a situation that led many utilities to construct thermal stations during this period. In addition, in the early 1960s, Canada began to develop nuclear energy as an alternative source for future energy demand.

CAPACITY ADDITIONS

Because of reduced electricity demand and energy conservation, there were only a few major capacity additions in 1991.

In October 1991, a 56 MW generating unit went into service at Hydro-Québec's Manic 5 PA power station. Three units (3 x 317 MW) at the La Grande 2A station were also commissioned in 1991. In addition, units 4, 5, 6, and 7 (4 x 133 MW) of Manitoba's Limestone hydroelectric project went into service between March and December 1991. The 150 MW unit at the Trenton coal-fired station, owned by Nova Scotia Power Corporation, was declared in-service in October 1991. New capacity additions totalled 1688 MW in 1991; of this total, 1538 MW was generated by hydro, and 150 MW by coal. Meanwhile, a small (4 MW) hydro station, owned by Ontario Hydro, was retired in 1991. (Table 7.1)

CAPACITY BY FUEL TYPE AND PROVINCE

Total installed capacity by fuel type and province for 1991 is given in Table 7.2. Although hydro's share of total installed capacity has declined, hydro is still the most important source of electrical energy in Canada. In 1991, hydro's capacity share accounted for more than 58 per cent of total installed capacity,

Table 7.1. Installed generating capacity by fuel type, 1960-1991

	Installed Generating Capacity					Average Annual Growth Rate	
Fuel Type	1960	1970	1980	1990	1991	1960-1991	1990-1991
			(MW)			(per cent)	
Hydro	18 643	28 298	47 770	58 701	60 235	3.9	2.6
Thermal	4 392	14 287	28 363	31 174	31 324	6.4	0.5
Nuclear*	0	240	5 866	13 052	13 052	-	0.0
Tidal**	0	0	0	20	20	-	0.0
Total	23 035	42 825	81 999	102 947	104 631	5.0	1.6

** Commercial operation started in 1968.*
*** Commercial operation started in 1984.*

Source: Electric Power Statistics, Volume II, Statistics Canada, catalogue 57-202.

compared with 81 per cent in 1960 (Figure 7.1).

In the 1960s and early-1970s, Quebec had the largest installed capacity in Canada. Since the mid-1970s, however, Ontario's capacity has been the largest. In 1991, Ontario's installed capacity was 31 per cent of the Canadian total, followed by Quebec with 29 per cent and British Columbia with 12 per cent. The combined total of these three provincial electrical systems accounted for 72 per cent of the total. Between 1960 and 1991, the Atlantic provinces had the major gain; their share increased from 5 per cent in 1960 to 13 per cent by 1991. The increase was due largely to the completion of the Churchill Falls project in Labrador in 1974, which added significantly to Newfoundland's installed capacity (Figure 7.2). Installed generating capacity by province for the period 1960-91 is shown in Table 7.3.

MAJOR HYDRO PLANTS IN CANADA

Canada is the world leader in large hydro-plant construction. Table 7.4 lists Canada's ten largest hydro stations in 1991. Churchill Falls, Canada's largest hydro plant (5429 MW), ranked sixth among the world's hydro plants by present capacity. La Grande 2, situated in the James Bay region of Quebec, is Canada's second-largest hydro plant with 5328 MW and ranked seventh in the world. La Grande 4, also in Quebec, ranked fourteenth. British Columbia's Gordon M. Shrum hydro plant and Quebec's La Grande 3 ranked eighteenth and twenty-first among the world's largest hydro plants in 1991[1].

Among Canada's ten largest hydro plants, five are located in Quebec, mainly in the James Bay area, three in British Columbia, and one each in Newfoundland and Ontario. These ten hydro stations have a total installed capacity of 25 932 MW, and in 1991 they accounted for about 43 per cent of Canada's total hydro capacity.

Table 7.2. Installed generating capacity by fuel type and province, 1991

	Coal	Oil	Natural Gas	Nuclear	Hydro	Other	Total
			(MW)				
Nfld.	0	807	0	0	6 650	5	7 462
P.E.I.	20	102	0	0	0	0	122
N.S.	1 312	589	0	0	386	19	2 306
N.B.	284	1 589	0	680	903	87	3 543
Que.	0	1 090	8	685	28 091	5	29 879
Ont.	10 653	2 710	445	11 687	7 143	91	32 729
Man.	369	17	4	0	4 533	23	4 946
Sask.	1 532	24	432	0	836	22	2 846
Alta.	5 541	1	1 632	0	734	68	7976
B.C.	0	242	1 036	0	10 849	370	12 497
Yukon	0	49	0	0	77	0	126
N.W.T.	0	126	20	0	53	0	199
Canada	19 711	7 346	3 577	13 052	60 255	690	104 631

Source: Electric Power Statistics, Volume II, Statistics Canada, catalogue 57-204 and Energy, Mines and Resources Canada.

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[1] *International Water Power and Dam Construction, June 1992.*

MAJOR CONVENTIONAL THERMAL STATIONS IN CANADA

In the 1950s and early-1960s, Canadian electric utilities built steam plants with a unit size of about 150 MW, although some units were as large as 300 MW. Since then, however, advances in technology, stable and cheap fossil-fuel prices, and robust electricity demand growth have led some electric utilities in Ontario and Alberta to build larger steam plants. For example, Ontario Hydro's Lambton and Nanticoke coal-fired stations have unit sizes of 510 MW and 512 MW respectively, while the Lennox oil-fired station has four units of 550 MW. Electric utilities in Alberta built coal-fired stations with unit sizes of about 400 MW.

Table 7.5 lists Canada's ten largest thermal stations in 1991. Seven of the ten stations are using coal as input fuel, two oil and one natural gas. Five of the ten largest thermal stations are located in Ontario, where a large population results in significant economies of scale. Two of the stations are in Alberta, and there is one each in New Brunswick, Saskatchewan and British Columbia. Total combined capacity for these stations is 17 780 MW, which accounted for 59 per cent of Canada's total conventional thermal installed capacity in 1991.

NUCLEAR POWER PLANTS IN CANADA

In the early-1960s, Canada started to develop nuclear energy as an alternative source for future energy demand. By 1991, Canada owned and operated 19 large CANDU reactors (500 MW and up), with a total installed net capacity of 12 748 MW. With the exceptions of Point Lepreau 1 in New Brunswick and Gentilly 2 in Quebec, they are all located in Ontario. Table 7.6 reports major nuclear power stations in Canada, in order of their commissioning date.

Table 7.3. Installed generating capacity by province, 1960-1991

	Installed Generating Capacity					Average Annual Growth Rate	
	1960	1970	1980	1990	1991	1960-1991	1990-1991
			(MW)			(per cent)	
Nfld.	314	1 248	7 195	7 462	7 462	10.8	0.0
P.E.I.	37	77	118	122	122	3.9	0.0
N.S.	507	931	2 029	2 156	2 306	5.0	7.0
N.B.	402	1 201	2 795	3 543	3 543	7.3	0.0
Quebec	8 920	14 047	20 531	28 873	29 879	4.0	3.5
Ontario	7 109	13 700	25 796	32 733	32 729	5.0	0.0
Manitoba	1 043	1 794	4 142	4 414	4 946	5.1	12.1
Sask.	761	1 533	2 340	2 846	2 846	4.3	0.0
Alberta	915	2 674	5 807	7 976	7 976	7.2	0.0
B.C.	2 963	5 473	10 525	12 497	12 497	4.8	0.0
Yukon	31	58	94	126	126	4.6	0.0
N.W.T.	33	89	180	199	199	6.0	0.0
Canada	23 035	42 825	81 999*	102 947	104 631	5.0	1.6

**Includes confidential data, not available by province.*

Source: Electric Power Statistics, Volume II, Statistics Canada, catalogue 57-202.

CANDU reactors (pressurized heavy water reactors) have been shown to be among the best nuclear reactors in the world in terms of cost-effectiveness, safety measures and output performance. Figure 7.3 indicates that among lifetime performance for four types of nuclear reactors, the CANDU has the highest capacity factor to December 31, 1991. In terms of lifetime performance for over 500 MW nuclear reactors worldwide, Canada's CANDU reactors comprised five of the ten best reactors (Figure 7.4).

SURPLUS CAPACITY

Because new generating facilities must be planned and built in advance of their actual need, electric utilities are constantly faced with the difficult task of anticipating future electricity demand. If utility planners expect that the future will be a period of rapid growth, then new generating stations may need to be built in order to meet the increased demand. On occasion, when new generating facilities are completed and the expected demand does not materialize, the utility is faced with excess generating capacity. For example, in the early-1970s, the construction of new generating stations was initiated mainly on the basis of expectations of continuing rapid growth in electricity demand. As growth in demand slowed dramatically in the latter part of the decade, some of these newly constructed stations became surplus to domestic requirements.

In calculating surplus capacity, the generating capability, rather than generating capacity, is normally used. Generating capability measures the expected power of all available generating facilities of the province (or country) at the time of one-hour firm peak load. This may differ from the generating capacity measured by the nameplate rating of the equipment.

The variations between generating capability and generating capacity may be caused by a number of factors. These include: (i) high water levels in reservoirs, resulting in a higher waterhead and greater generation than the nameplate capacity; (ii) the impossibility of placing all pieces of equipment on the line at the same time; and (iii) low

Figure 7.1. Installed generating capacity by fuel type

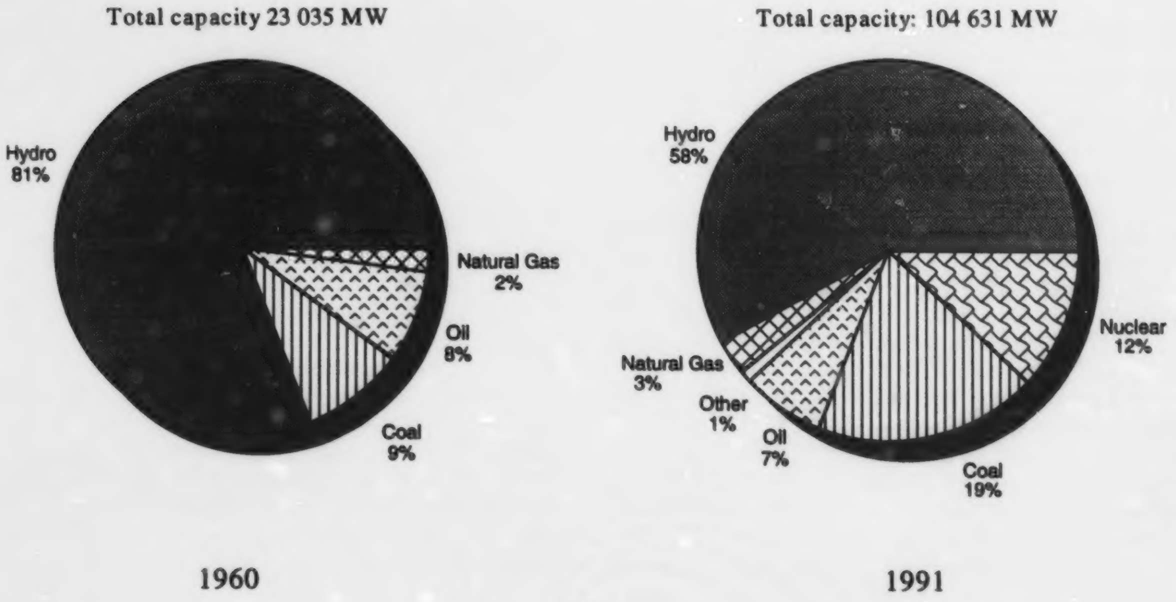
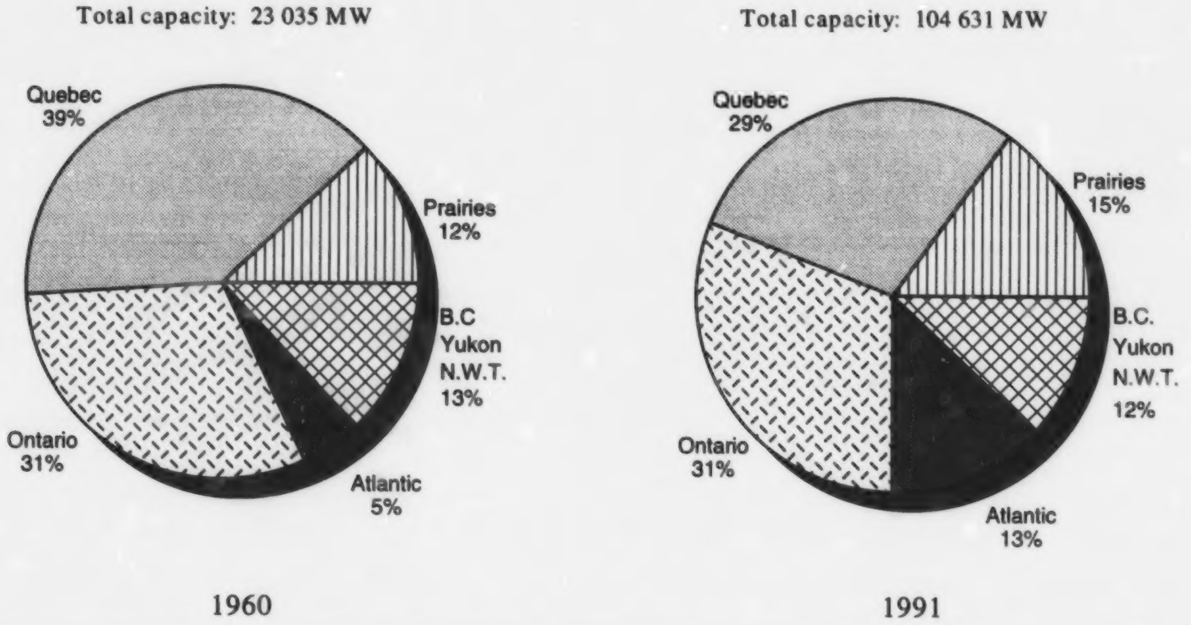


Figure 7.2. Installed generating capacity by region



water, ice or unreliable equipment, all of which may result in capability below capacity.

PRESENT RESERVE MARGIN

The reserve margin of an electrical system is defined as the excess of generating capability for in-province use over the in-province firm peak that occurred during the year, expressed as a percentage of in-province firm peak. Table 7.7 presents the reserve margins of the ten provinces and two territories in 1991. Utilities in the Yukon and Northwest territories have high reserve margins because of the need to install extra generators in the many remote communities they serve. The extra generators allow the utilities to continue to provide service in the event of equipment failure.

CAPACITY RESERVE REQUIREMENTS

Normal practice in an electrical system is to reserve a certain amount of capacity (expressed as a percentage of firm peak load) to allow for the scheduled maintenance of equipment, planned outages and unexpected peak demand. This portion is usually called the capacity reserve requirement, and it varies from utility to utility, depending on the capacity mix of the particular system. Column 4 of Table 7.7 reports the capacity reserve requirement in each province and territory for 1991.

NET SURPLUS CAPACITY

Net surplus capacity is defined as the reserve margin less the reserve capacity requirement. Table 7.7 indicates existing net surplus generating capacity by province and for Canada as a whole for 1991. With the exceptions of New Brunswick, Nova Scotia, and Alberta, all provinces and territories had small net surplus capacity by the end of 1991. A weighted average for Canada was about five per cent.

HYDROELECTRIC POTENTIAL IN CANADA

There is still a large amount of undeveloped hydroelectric potential in Canada (Table 7.8 and Appendix C). Although much of this is unlikely to be developed due to the remoteness of the sites, the physical difficulty of the terrain or because of environmental concerns, it is anticipated that a significant amount will be developed over the next 20 to 25 years. Quebec, British Columbia, Manitoba and Newfoundland have most of the remaining river potential. Tidal resources are located in Nova Scotia, Quebec and British Columbia.

Table 7.4. Canada's largest hydro stations, 1991

Rank	Name	Province	Rated Capacity (MW)	Year of Initial Operation
1	Churchill Falls	Newfoundland	5 429	1971
2	La Grande 2	Quebec	5 328	1979
3	La Grande 4	Quebec	2 651	1984
4	Gordon M. Shrum	B.C.	2 416	1968
5	La Grande 3	Quebec	2 304	1982
6	Revelstoke	B.C.	1 843	1984
7	Mica	B.C.	1 736	1976
8	Beauharnois	Quebec	1 645	1932
9	Manic 5	Quebec	1 292	1970
10	Sir Adam Beck 2	Ontario	1 288	1954

Source: Electric Power Statistics, Volume III, Statistics Canada, catalogue 57-206, 1990.

Table 7.5. Canada's largest conventional thermal stations, 1991

Rank	Name	Fuel Type	Province	Rated Capacity (MW)	Year of Initial Operation
1	Nanticoke	coal	Ontario	4 096	1973
2	Lakeview	coal	Ontario	2 400	1962
3	Lennox	oil	Ontario	2 200	1976
4	Sundance	coal	Alberta	2 200	1970
5	Lambton	coal	Ontario	2 040	1969
6	Richard L. Hearn	coal	Ontario	1 200	1951
7	Coleson Cove	oil	New Brunswick	1 050	1976
8	Burrard	natural gas	British Columbia	913	1962
9	Boundary Dam	coal	Saskatchewan	875	1959
10	Keephills	coal	Alberta	806	1983

Source: Electric Power Statistics, Volume III, Statistics Canada, catalogue 57-206, 1990

Table 7.6. **Commercial nuclear power plants in Canada, 1991**

	Plant Name	Province	Rated Net Capacity (MW)	Commissioning Date
1	Pickering A1	Ontario	515	1971
2	Pickering A2	Ontario	515	1971
3	Pickering A3	Ontario	515	1972
4	Pickering A4	Ontario	515	1973
5	Bruce A1	Ontario	769	1977
6	Bruce A2	Ontario	769	1977
7	Bruce A3	Ontario	769	1978
8	Bruce A4	Ontario	769	1979
9	Point Lepreau 1	New Brunswick	635	1983
10	Pickering B5	Ontario	516	1983
11	Gentilly 2	Quebec	638	1983
12	Pickering B6	Ontario	516	1984
13	Bruce B6	Ontario	837	1984
14	Pickering B7	Ontario	516	1985
15	Bruce B5	Ontario	860	1985
16	Pickering B8	Ontario	516	1986
17	Bruce B7	Ontario	860	1986
18	Bruce B8	Ontario	837	1987
19	Darlington 2	Ontario	881	1990

Source: Electricity Branch, Energy, Mines and Resources Canada.

Table 7.7. Surplus capacity in Canada, 1991

	Net Generating Capability for In-Province Use (1)	In-Province Firm Peak (2)	Reserve Margin $(3)=\frac{((1)-(2))}{(2)}$	Capacity Reserve Requirement (4)*	Net Surplus Capacity (5)= (3)-(4)
	(MW)		(per cent)		
Nfld.**	1 871	1 484	26	17	9
P.E.I.	158	135	17	15	2
N.S.	2 077	1 825	14	20	-6
N.B.	2 869	2 627	9	20	-11
Quebec	31 986	27 331	17	10	7
Ontario	30 869	23 752	30	24	6
Manitoba	4 287	3 524	22	15	7
Sask.	2 855	2 356	21	15	6
Alberta	7 739	6 509	19	22	-3
B.C.	11 147	9 329	19	15	4
Yukon	128	82	56	19	37
N.W.T.	192	107	79	30	49
Canada	96 178	79 061	22	17	5

* *Expressed as a percentage of in-province firm peak.*

** *Does not include Labrador.*

Source: Electric Power Statistics, Volume I, Statistics Canada, catalogue 57-204.

Table 7.8. Hydroelectric capacity in Canada, 1991

Province/Territory	In-Operation and Under Construction	Remaining Potential		
		Gross*	Identified**	Planning***
		(MW)		
Newfoundland	6 656	5 201	4 623	2 555
Prince Edward Island	0	0	0	0
Nova Scotia	386	8 499	8 499	0
New Brunswick	903	940	600	440
Quebec	31 768	68 497	37 055	15 453
Ontario	7 796	12 385	12 385	4 024
Manitoba	4 932	8 360	5 260	5 260
Saskatchewan	836	2 189	935	870
Alberta	734	18 813	9 762	1 923
British Columbia	10 849	33 137	18 168	10 538
Yukon	77	18 583	13 701	350
Northwest Territories	53	9 229	9 201	2 473
Canada	64 990	185 833	120 189	43 886

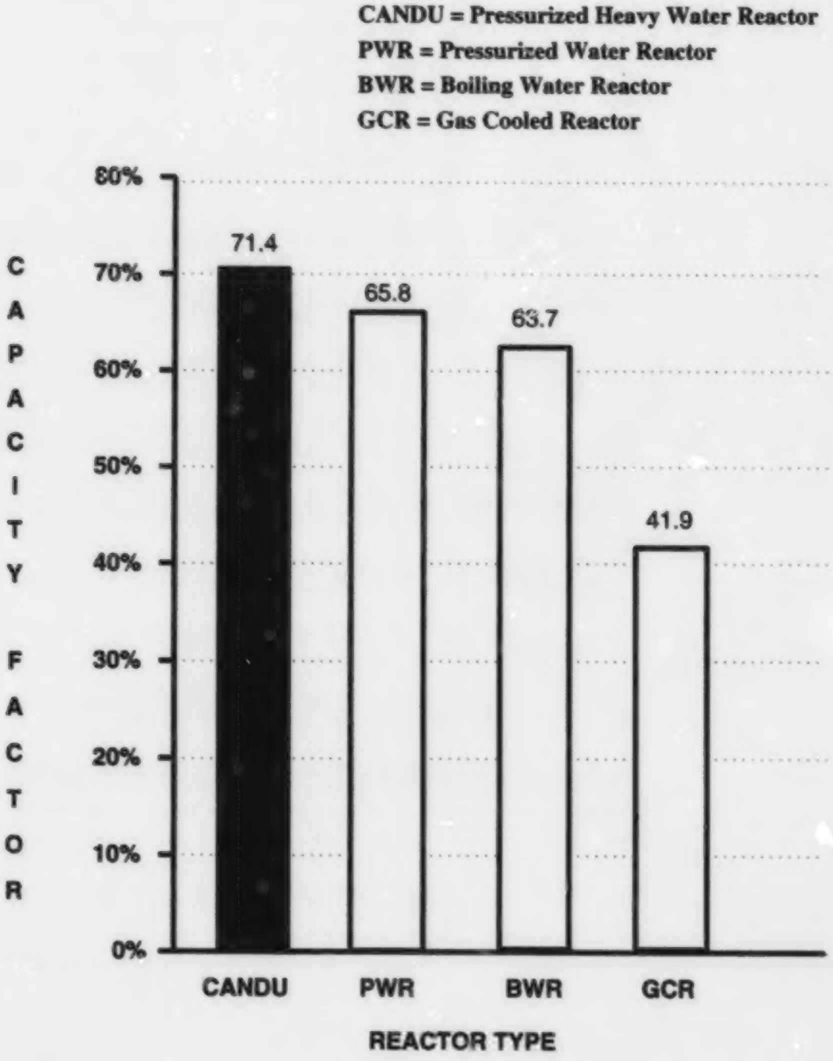
**Gross Potential -- The total gross resource that could be developed if there were no technical, economic or environmental constraints (excludes sites already developed or under construction).*

*** Identified Potential -- Gross potential less sites that may not be developed for technical reasons.*

**** Planning Potential -- Identified potential less sites that may not be developed for environmental or economic reasons. The planning potential thus comprises all those sites that are considered to be likely candidates for future development.*

Source: Canadian electrical utilities and Energy, Mines and Resources Canada.

Figure 7.3. Nuclear reactor performance worldwide by type*

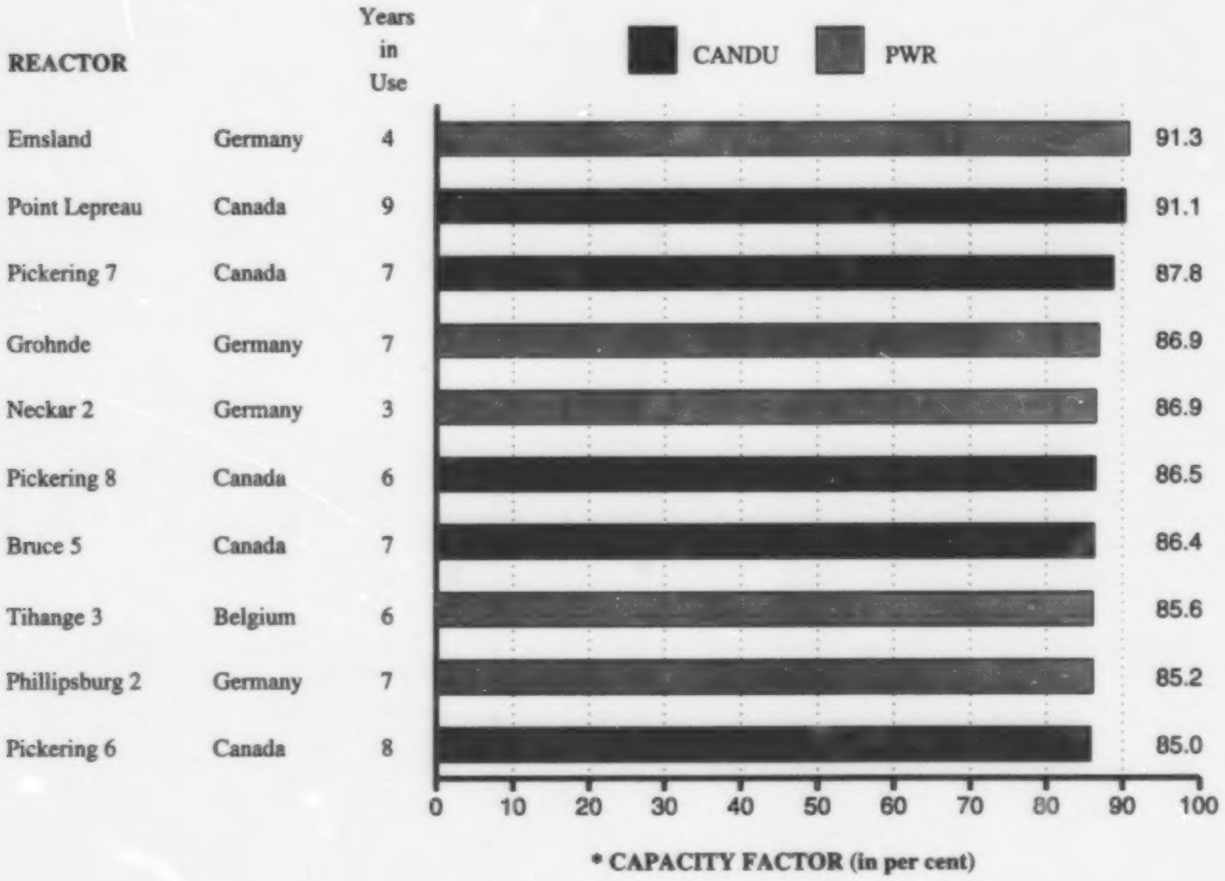


Reactors > 500 MW
***Lifetime to end of December 31, 1991**

Sources: World Nuclear Industry Handbook 1992 and Atomic Energy of Canada Limited.

Figure 7.4. World nuclear reactor performance to December 31, 1991

(Reactors over 500 MW)



** Capacity factor =* $\dfrac{\textit{actual electricity generation}}{\textit{perfect electricity generation}}$

Sources: Nuclear Engineering International, April 1992.

8. ELECTRICITY TRADE

INTERNATIONAL TRADE

Electricity trade between Canada and the United States dates back to the beginning of the century. In 1901, the first electric power transmission line between Canada and the United States was built at Niagara Falls. This interconnection enabled abundant Canadian hydroelectric power to be marketed in the United States. This historical event set the stage for continued electricity exchanges between Canada and the United States in a climate of international cooperation and coordination. Since 1921, electricity trade has been favoured to Canada in terms of quantity. In particular, Canada's net exports grew substantially from the early-1970's reaching a peak in 1987, largely due to the high cost of thermal production in the United States.

In 1988, electricity exports to the United States began to decline in both quantity and revenue, due mainly to drought conditions and higher domestic demand. This downward trend continued into 1989 and 1990. However, electricity trade began to recover in 1991. Increased interruptible exports combined with reduced import levels resulted in net exports (excluding non-cash service exchanges) of 17 923 GW.h, compared to 951 GW.h in 1990. Net export revenues also increased substantially, to $487 million in 1991, compared to net costs of $9 million in 1990.

Electricity exports rose 20 per cent in 1991, to 19 828 GW.h, while imports from the United States declined 88 per cent to 1905 GW.h. Exports accounted for 4.1 per cent of Canada's total electricity generation in 1991, up from 3.5 per cent in 1990 (Table 8.1).

The return to a more favourable electricity trade balance was due largely to events in Ontario. In 1990, Ontario Hydro reduced coal-fired generation and relied more heavily on electricity

Table 8.1. Canada-U.S. electricity trade, 1960-1991

	Exports* (GW.h) (1)	Exports as a Percentage of Net Generation (2)	Export Revenues ($million) (3)	Imports* (GW.h) (4)	Imports as a Percentage of Total Disposal** (5)	Import Cost ($million) (6)	Net Exports	
							GW.h (7)= (1)-(4)	$Million (8)= (3)-(6)
1960	5 496	4.8	14	357	0.3	1	5 139	13
1965	3 684	2.6	8	3 575	2.5	3	109	5
1970	5 631	2.8	32	3 245	1.6	9	2 386	23
1975	11 409	4.2	104	3 972	1.5	3	7 819	102
1980	28 224	7.7	773	168	0.1	3	28 056	791
1985	41 441	9.3	1 425	231	0.1	9	41 210	1 416
1987	45 359	9.4	1 211	536	0.1	12	44 823	1 199
1988	29 729	6.1	880	2 853	0.6	63	26 879	817
1989	18 462	3.8	661	8 747	1.9	292	9 715	369
1990	16 494	3.5	547	15 543	3.5	556	951	(9)
1991	19 828	4.1	558	1 905	0.4	71	17 923	487

* *Exports and imports prior to 1977 include service exchanges.*

** *Total disposal refers to total electricity available for domestic consumption.*

Source: Electric Power Statistics , Volume II, Catalogue 57-202, Statistics Canada and Energy, Mines and Resources Canada.

Table 8.2. Provincial shares of Canadian electricity exports, 1960-1991*

Year	N.B.	Que.	Ont.	Man.	Sask.	B.C.	Canada
1960	3.0	10.4	86.6	0.0	0.0	0.0	100.0
1965	6.4	1.3	84.0	0.0	0.0	8.3	100.0
1970	13.4	0.9	63.9	5.2	0.0	16.6	100.0
1975	14.2	8.0	42.5	10.3	0.0	25.0	100.0
1980	13.8	28.7	40.5	11.8	0.0	5.2	100.0
1985	14.8	23.1	22.5	13.6	0.3	25.7	100.0
1989	24.1	30.9	14.7	6.6	0.1	23.6	100.0
1990	25.4	30.9	4.5	11.7	0.3	27.2	100.0
1991	15.6	29.2	11.7	16.7	0.3	26.6	100.0

* *Excludes non-cash exchanges.*

Source: National Energy Board.

Table 8.3. Firm and interruptible exports by province, 1991*

	Firm	Interruptible	Firm	Interruptible
	(GW.h)		(per cent)	
New Brunswick	2 238	848	73	27
Quebec	4 405	1 379	76	24
Ontario	234	2 080	10	90
Manitoba	812	2 503	25	75
Saskatchewan	0	59	0	100
British Columbia	1 099	4 170	21	79
Canada	8 789	11 039	44	56

* *Exchanges are excluded.*

Source: National Energy Board.

purchases from neighbouring utilities as a strategy for meeting provincial limits on acid gas emissions. However, low load growth in 1991 and the installation of flue gas conditioning equipment at the utility's major coal-fired stations allowed Ontario Hydro to return to its policy of purchasing power for economic reasons only. Interruptible exports from Ontario rose to 2080 GW.h, more than four times their 1990 level. Electricity imports from the United States to Ontario declined 92 per cent.

Improving water conditions in British Columbia and Quebec, and the addition of seven units at Manitoba Hydro's Limestone generating station in late 1990 and 1991, also contributed to increased electricity exports. Interruptible sales rose considerably in Quebec, Manitoba, and British Columbia. Manitoba Hydro also increased its firm sales to the United States.

Firm and interruptible exports from New Brunswick decreased in 1991, reflecting lower sales to Maine and Massachussets under renegotiated contracts with utilities in those states. Slow economic growth, rapid development of independent power production, and the success of energy efficiency programs in the U.S. Northeast have reduced the current U.S. demand for electricity from New Brunswick.

Provincial shares of electricity exports for 1960-91 are shown in Table 8.2. Table 8.3 reports firm and interruptible electricity exports to the United States by province, and Table 8.4 reports exports to the United States by type of energy transaction for the period 1960-91. Firm exports accounted for 44 per cent of total Canadian electricity exports in 1991. The share of firm exports ranged from 0 per cent in Saskatchewan to 76 per cent in Quebec. All provinces experienced a decrease in firm electricity export shares in 1991, with the exception of New Brunswick and Manitoba. The revenue share of firm exports was 56 per cent in 1991. During the past 30 years, firm exports have fluctuated between 14 and 53 per cent, while interruptible exports ranged from 47 to 86 per cent.

Tableau 8.4. Electricity exports to the United States by type, 1960-1991

	Quantity (GW.h)		Revenue ($1000)		Quantity Share (%)		Revenue Share (%)	
	Firm*	Interruptible**	Firm	Interruptible	Firm	Interruptible	Firm	Interruptible
1960	1 040	4 456	4 328	10 023	19	81	30	70
1965	635	3 049	4 261	3 322	17	83	56	44
1970	984	4 648	6 828	25 309	18	82	21	79
1975	2 375	9 034	20 382	84 488	21	79	19	81
1980	7 232	20 992	156 731	636 760	26	74	20	80
1985	12 305	29 1365	547 109	877 657	30	70	38	62
1989	8 378	10 084	350 666	310 692	45	55	53	47
1990	8 701	7 794	346 513	200 147	53	47	63	37
1991	8 789	11 039	310 049	247 484	44	56	56	44

* *Electrical energy intended to be available at all times during the period of the agreement for its sale.*

** *Energy made available under an agreement that permits curtailment or interruption of delivery at the option of the supplier.*

Source: Electric Power Statistics, Volume II, catalogue 57-202, Statistics Canada, and Energy, Mines and Resources Canada.

Average Canadian export revenues for the period 1960-91 are reported in Table 8.5. As indicated, firm exports are generally more valuable than interruptible exports. This has been the case in all years except 1974-75 and 1979-81.

Both average firm and interruptible export revenues fell in 1991. Average firm revenues dropped 11 per cent to 35.3 mills per kW.h in 1991, from 39.8 mills per kW.h in 1990, while average interruptible export revenues dropped 13 per cent, from 25.7 mills per kW.h in 1990 to 22.4 mills per kW.h in 1991.

Provincial exports, revenues and average revenues received in 1990-91 are reported in Table 8.6. The average revenue received from electricity exports in 1991 varied significantly from province to province. New Brunswick received the highest average revenue, 47.1 mills per kW.h, while Saskatchewan received the lowest, 11.7 mills per kW.h. This variance reflects the differences in products exported, costs of generation, and the alternatives available in the export markets. Average revenues dropped for all of the six exporting provinces in 1991.

As presented in Table 8.7, firm export revenues decreased in all provinces except British Columbia, while average interruptible revenues decreased in all provinces. New Brunswick's average firm export revenues led those of the other provinces, reflecting its export market (oil-dependent New England) as well as the terms of its unit participation contract for the Lepreau 1 nuclear generating station. New Brunswick's average interruptible revenue was also the highest.

Table 8.8 summarizes the generating sources of electricity exports to the United States during the period 1975-91.

Hydro-generated electricity continued to be the main source of Canada's electricity exports, accounting for 72 per cent of the total exported in 1991. Nuclear generated exports have been significant since 1983.

Electric utilities in the past seldom used natural gas to generate electricity for export purposes. However, in 1989, B.C. Hydro reactivated its Burrard natural gas-fired station to alleviate the reduced electrical output caused by low water conditions in the province. Gas-fired exports from British Columbia have been declining since 1989 with improving water conditions in the province.

Table 8.9 reflects the energy sources of electricity exported during 1991 on a provincial basis. Hydro-generated exports continued to dominate in Quebec, Manitoba, and British Columbia. Coal-fired facilities produced all of Saskatchewan's

Table 8.5. Average export revenues, 1960-1991

Year	Firm	Interruptible	Total
		(mills/kW.h)	
1960	4.2	2.3	2.6
1965	6.7	1.1	2.1
1970	6.9	5.5	5.7
1975	8.6	9.4	9.2
1980	21.7	30.3	28.1
1985	44.5	30.1	34.4
1989	41.9	30.8	35.8
1990	39.8	25.7	33.1
1991	35.3	22.4	28.1

Source: Calculated from Electric Power in Canada, 1990, Table 8.2.

Table 8.6. Electricity exports and revenues by province, 1990-1991*

	Quantity (GW.h)			Revenue (million $)			Average Revenue (mills/kW.h)		
	1990	1991	% Change	1990	1991	% Change	1990	1991	% Change
N.B.	4 185	3 086	-26	198.6	145.41	-27	47.5	47.1	-1
Que.	5 098	5 784	13	180.0	169.51	-6	35.3	29.3	-17
Ont.	738	2 314	213	25.1	65.21	160	34.0	28.2	-17
Man.	1 932	3 316	72	33.9	57.31	69	17.5	17.3	-1
Sask.	60	59	-2	0.7	0.69	-8	12.3	11.7	-5
B.C.	4 481	5 269	18	108.3	119.4	10	24.2	22.7	-6
Canada	16 494	19 828	20	546.6	557.5	2	33.1	28.1	-15

** Excludes non-cash exchanges.*

Source: National Energy Board.

Table 8.7. Average export revenues by province, 1990 vs 1991

	Firm		Interruptible	
	1990	1991	1990	1991
	(mills/kWh)			
New Brunswick	54.6	53.3	37.9	30.9
Quebec	35.6	30.2	31.8	26.4
Ontario	40.1	30.2	31.1	27.9
Manitoba	29.7	22.4	15.6	15.6
Saskatchewan	-	-	12.5	11.7
British Columbia	28.2	29.5	22.8	20.9
Canada	39.8	35.3	25.7	22.4

Source: Canada-U.S. Electricity Trade Report, Energy, Mines and Resources exports and the majority of Ontario Hydro's exports. Nuclear-generated exports accounted for 70 per cent of electricity exports from New Brunswick during the year. The majority of oil-fired exports were generated in New Brunswick, with imported oil.

Canadian electricity export markets in the United States are summarized in Table 8.10. New England continued to be Canada's main electricity market in terms of both revenues and export quantities. New York was also an important market. Together, these two regions accounted for 56 per cent of Canadian electricity exports and 67 per cent of export revenues in 1991. California was the third most important Canadian electricity export market. In terms of revenues, its share accounted for 14 per cent of the total in 1991. The Midwest, mainly Minnesota, also increased its shares of Canadian export quantities and revenues, by 18 and 11 per cent respectively. Exports to the Pacific Northwest accounted for about 8 per cent of Canada's total export revenues in 1991. Exports to the State of Michigan, once an important Canadian market, have declined to less than 1 per cent in recent years. This is due to lower Ontario Hydro exports, as well as recent capacity additions in that state.

U.S. imports of Canadian electricity, as a percentage of total electrical energy demand in the United States, decreased from 1 per cent in 1988 to 0.6 per cent in 1990, and increased slightly to 0.7 per cent in 1991. However, the dependence of the United States on Canadian exports was higher in certain regions. Exports to New England accounted for 7 per cent of the region's total electricity consumption in 1991. The corresponding ratio was 3 per cent for the Midwest; 2 per cent for New York; and 1 per cent each for the Pacific Northwest

Table 8.8. Generation sources of Canadian electricity exports, 1975-1991

	Hydro	Imported Coal	Imported Oil	Domestic Coal/Oil	Nuclear	Natural Gas	Total
				(GW.h)			
1975	5 724	4 838	494	353	0	-	11 409
1976	6 973	4 323	1 206	302	0	-	12 804
1977	7 926	8 514	2 961	555	0	-	19 957
1978	7 290	10 476	2 260	411	0	-	20 437
1979	15 213	11 587	3 354	128	177	-	30 458
1980	14 135	10 599	2 867	593	30	-	28 224
1981	21 182	10 901	1 940	665	42	-	34 730
1982	20 114	10 315	1 959	502	96	-	32 986
1983	21 978	11 704	1 201	519	1 856	-	37 258
1984	22 807	10 582	1 552	711	1 911	-	37 563
1985	28 836	8 245	1 157	956	2 247	-	41 441
1986	25 727	5 389	846	825	2 484	-	35 271
1987	34 065	7 575	1 270	408	2 041	-	45 359
1988	19 621	4 531	1 393	2 033	2 151	-	29 729
1989	9 054	1 452	1 089	2 214	2 032	2 621	18 462
1990	11 299	266	885	1 244	2 054	796	16 494
1991	14 415	1 546	610	697	2 172	388	19 828

Source: Compiled from National Energy Board statistics.

and the California and Southern Nevada region.

ELECTRICITY TRADE AND THE ECONOMY

The export of electricity is an important aspect of Canada's foreign trade, while total electricity export revenue accounted for only 0.4 per cent of total merchandise exports and 3.4 per cent of total energy exports in 1991, net electricity export revenue accounted for 6.6 per cent of Canada's balance of trade and 5.2 per cent of Canada's total energy trade balance in 1991. Canadian energy trade by fuel type during the period 1975-91 is reported in Table 8.11.

INTERPROVINCIAL TRADE

Annual Canadian interprovincial electricity trade for the period 1960-91 is summarized in Table 8.12. When the Churchill Falls hydro project began producing electricity in 1972, the volume of interprovincial electricity trade increased substantially, because Newfoundland sold almost all of the output to Quebec under contract. Interprovincial electricity trade reached a peak in 1975, accounting for about 18 per cent of total Canadian generation; the percentage has declined gradually since then. In 1991, interprovincial exchanges totalled 38 530 GW.h, which accounted for about 7.9 per cent of Canada's total generation.

Interprovincial transfers during the period 1982-91 are summarized in Table 8.13. More information on exports and imports by province is provided in Figure 8.1 and Table A5 in Appendix A.

Table 8.9. Energy sources of electricity exports, 1991

	Natural Gas	Oil	Coal	Nuclear	Hydro	Other*	Total	Energy Exported
			(per cent)					(GW.h)
New Brunswick	-	23	4	70	3	1	100	3 086
Quebec	-	-	-	-	100	-	100	5 784
Ontario	-	6	74	15	2	2	100	2 314
Manitoba	-	-	1	-	95	4	100	3 316
Saskatchewan	-	-	100	-	-	-	100	59
British Columbia	7	-	7	-	86	-	100	5 269
Canada	2	3	11	11	72	1	100	19 828

**Refers to U.S. electricity imports that are subsequently exported.*

Table 8.10. Exporting provinces and importing markets, 1991*

Exporting Province	Importing Market	Quantity (MW.h)	Value ($1000)
New Brunswick	Maine	1 244 729	47 462
	Massachusetts	1 668 470	89 488
Quebec	Maine	498	34
	Vermont	1 459 553	56 685
	New England (NEPOOL)**	3 222 945	72 026
	New York	1 088 724	34 463
Ontario	Vermont	23 212	1 858
	New York	2 183 376	60 965
	Michigan	107 609	2 347
Manitoba	Minnesota	3 118 648	53 193
	North Dakota	194 897	4 063
Saskatchewan	North Dakota	58 646	685
British Columbia	Washington	739 200	18 196
	Oregon	1 322 963	24 177
	Idaho	144 321	1 840
	Montana	25 432	271
	California	3 028 885	74 716
	Nevada	7 950	140
	Alaska	55	5
Canada	United States	19 640 112	542 614

* *Excludes non-cash exchanges.*

** *The New England Power Pool (NEPOOL) coordinates electrical service to member utilites in New Hampshire, Maine, Vermont, Massachussets, Connecticut and Rhode Island.*

Source: National Energy Board.

Table 8.11. Canadian energy trade, 1975-1991

	Oil	Natural Gas	Coal	Electricity	Uranium	Total Energy
			($ million)			
1975						
Exports	3 684	1 092	483	104	133	5 496
Imports	3 508	8	643	13	12	4 184
Balance	176	1 084	-160	91	121	1 312
1980						
Exports	5 352	3 984	824	773	870	11 803
Imports	7 545	0	882	3	17	8 447
Balance	-2 193	3 984	-58	770	853	3 356
1985						
Exports	9 379	4 011	2 041	1 425	825	17 681
Imports	5 315	0	1 077	8	28	6 428
Balance	4 064	4 011	964	1 417	797	11 253
1987						
Exports	7 029	2 527	1 696	1 200	886	13 338
Imports	4 809	0	843	9	18	5 679
Balance	2 220	2 527	853	1 191	868	7 659
1988						
Export	6 338	2 954	2 063	881	585	12 821
Imports	4 341	0	828	63	75	5 307
Balance	1 997	2 954	1 235	818	510	7 514
1989						
Exports	6 723	3 017	2 201	659	456	13 056
Imports	5 408	0	777	297	109	6 591
Balance	1 315	3 017	1 424	362	347	6 465
1990						
Exports	9 298	3 280	2 276	539	315	15 708
Imports	7 384	0	684	568	105	8 741
Balance	1 914	3 280	1 592	-29	210	6 967
1991						
Exports	9 607	3 512	2 206	554	290	16 169
Imports	6 104	33	523	71	62	6 793
Balance	3 503	3 479	1 683	483	228	9 376

Source: Statistics Canada, Exports by Commodities (65-004) and Imports by Commodities (65-007).

Table 8.12. Annual Canadian interprovincial electricity trade, 1960-1991

Year	Total Canadian Generation (GW.h)	Delivered to other Provinces (GW.h)		Percentage of Interprovincial Transfers to Total Generation	
		With Churchill Falls*	Without Churchill Falls	With Churchill Falls	Without Churchill Falls
1960	114 378	7 108	7 108	6.2	6.2
1965	144 274	6 230	6 230	4.3	4.3
1970	204 723	8 137	8 137	4.0	4.0
1975	273 392	49 198	19 684	18.0	7.2
1980	367 306	52 709	14 965	14.4	4.1
1985	446 413	51 663	19 917	11.6	4.5
1989	482 158	36 176	11 809	7.5	2.4
1990	465 967	37 499	11 335	8.0	2.4
1991	489 227	38 530	12 164	7.9	2.5

* *The Churchill Falls project was completed in 1974 (the initial operation started in 1971). Over 90% of the energy it produces flows into Quebec under a contract that terminates in the year 2041.*

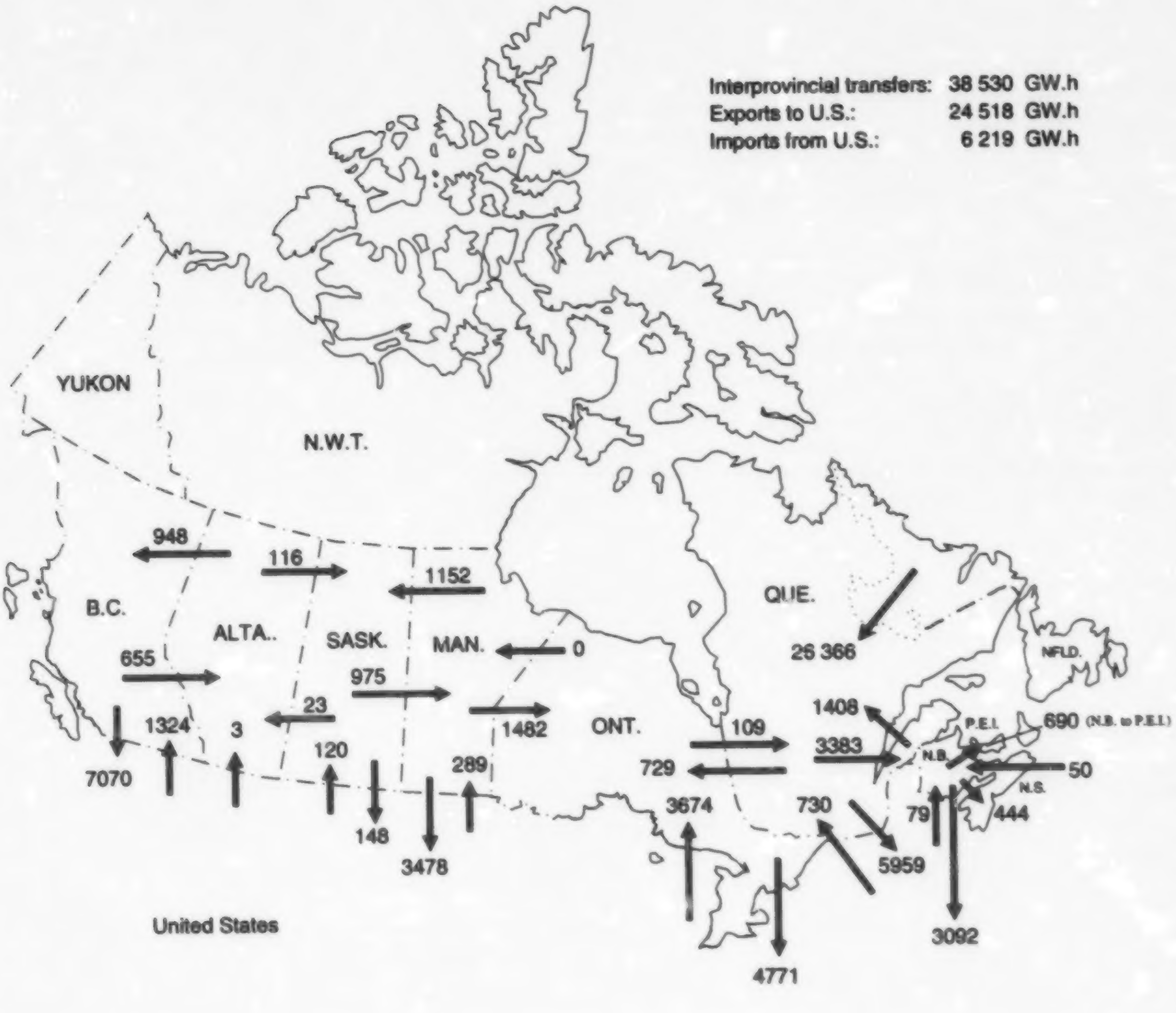
Source: Energy, Mines and Resources Canada.

Table 8.13. Interprovincial electricity trade by destination, 1982-1991

	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991
					(GW.h)					
Newfoundland to Quebec	35 779	31 229	36 012	31 836	30 695	30 393	30 727	24 367	26 164	26 366
Nova Scotia to New Brunswick	133	121	271	190	71	82	166	341	116	50
New Brunswick to Nova Scotia	217	737	303	360	620	659	186	441	365	444
New Brunswick to P.E.I.	478	520	550	585	610	483	486	622	672	690
New Brunswick to Quebec	0	1	0	2	0	20	309	951	1 116	1 408
Quebec to New Brunswick	3 615	3 971	4 342	5 951	7 204	6 840	2 690	1 966	2 659	3 383
Quebec to Ontario	5 768	5 378	7 364	8 685	7 292	5 942	2 289	1 032	690	729
Ontario to Quebec	57	52	68	106	17	15	43	80	134	109
Ontario to Manitoba	3	13	2	0	5	3	22	11	6	0
Manitoba to Ontario	1 066	955	940	959	735	1 050	538	1 303	1 636	1 482
Manitoba to Saskatchewan	1 488	1 610	1 593	1 530	1 211	1 262	1 370	1 171	1 058	1 152
Saskatchewan to Manitoba	1 066	1 209	1 299	1 240	1 076	1 220	1 109	1 115	1 047	975
Saskatchewan to Alberta	3	2	3	0	0	0	0	15	39	23
Alberta to Saskatchewan	0	4	0	0	0	0	0	42	94	116
Alberta to B.C.	188	46	259	182	617	710	1 218	2 477	1 242	948
B.C. to Alberta	442	163	296	37	553	521	364	242	461	655
Total	50 303	46 007	54 302	51 663	50 706	49 201	41 517	36 176	37 499	38 530

Source: Energy, Mines and Resources Canada.

Figure 8.1. Electricity Trade, 1991 (GW.h)*


Interprovincial transfers: 38 530 GW.h
Exports to U.S.: 24 518 GW.h
Imports from U.S.: 6 219 GW.h
YUKON
N.W.T.
B.C.
ALTA..
SASK.
MAN.
ONT.
QUE.
NFLD.
P.E.I.
N.B.
N.S.
United States
948
116
1152
655
975
0
23
1482
1324
3
7070
120
148
3478
289
26 366
1408
109
3383
729
690 (N.B. to P.E.I.)
50
3674
730
79
444
5959
3092
4771

* *Includes non-cash exchanges*

9. TRANSMISSION

TRANSMISSION CIRCUIT LENGTH

The electric power system in Canada consists of three interrelated functions: the generating system which produces the power; the transmission network which conducts the flow of power from the point of generation to the point of distribution; and the distribution system which delivers the power to consumers. In most provinces, all three of these interrelated functions are provided by one or a few major electric utilities.

The electrical transmission network in Canada has evolved from a simple system designed to serve customers at the local level into a highly complex interconnected system. In the early years of the 20th century, relatively small generating plants were situated close to the loads which they served, with power transmitted at low voltages under 60-kV.

Fast growth in electricity demand throughout the early 20th century brought forth successively larger power plants that were constructed farther away from load centers and nearer to abundant water resources. Transmission systems were used to distribute power to the geographically dispersed load areas. The integrated electric power system, coupled with the growth in interconnection of previously isolated power networks, led to the development of a new generation of higher voltage transmission in the range of 100 to 230-kV.

After World War II, in response to rapid electrification and installation of larger hydro and thermal generating stations, much higher voltages of transmission lines, such as 345-kV, 500-kV, 735-kV, and ± 450(DC) were introduced into commercial operation.

Total circuit length of electrical transmission in Canada for lines rated at 50-kV and above, increased by 1353 km in 1991. The total length of Canadian bulk transmission is now 153 516 km, with the largest share (32 per cent) being in the 100-kV to 149-kV range. Another 25 per cent is in the 200-kV to 299-kV range, while 21 per cent is

Table 9.1. Transmission circuit length in Canada, 1991

	50 - 99 kV	100 - 149 kV	150 - 199 kV	200 - 299 kV	300 - 399 kV	400 - 599 kV	600 kV and up	Total
				(km)				
Nfld.	2 356	1 970	-	2 005	-	-	612	6 943
P.E.I.	390	193	-	-	-	-	-	583
N.S.	2 027	1 703	-	1 159	251	-	-	5 140
N.B.	2 716	2 048	-	629	969	-	-	6 362
Quebec	4 150	7 762	2 266	3 810	7 138	1 550	9 955	36 631
Ontario	247	12 318	-	13 917	6	2 778	-	29 266
Manitoba	6 756	4 266	-	4 476	-	2 042	-	17 540
Sask.	4 849	4 534	-	2 977	-	-	-	12 360
Alberta	3 481	9 216	-	5 926	-	215	-	18 838
B.C.	4 996	4 702	316	3 430	403	5 344	-	19 191
Yukon	65	497	-	-	-	-	-	562
N.W.T.	100	-	-	-	-	-	-	100
Canada	32 133 (21%)	49 209 (32%)	2 582 (2%)	38 329 (25%)	8 767 (6%)	11 929 (7%)	10 567 (7%)	153 516 (100%)

Source: Statistics Canada publication 57-202 and Energy, Mines and Resources Canada.

between 50-kV and 99-kV (Table 9.1). Newfoundland and Quebec are the only two provinces with transmission lines over 600-kV. Newfoundland has three 735-kV lines wheeling power from its Churchill Falls hydro station to Quebec City and Montreal, and Quebec has five 735-kV lines delivering power from three hydro stations in the James Bay region to Montreal and the United States. Quebec also has a 765-kV line used mainly for export purposes, which delivers power from Chateauguay to the State of New York.

In 1991, transmission line additions within the provinces were found mainly in Saskatchewan, Quebec, and Ontario. SaskPower increased its 138-kV line by 430 km from Island Falls to Points North, and extended its 230-kV line by 201 km from Brada to Meadow Lake. Hydro-Québec increased its system by 237 km with the addition of one 450-kV line from Hervey Junction (near Quebec City) to Des Cantons (near the Vermont Border). Hydro-Québec also increased its 161-kV line by 76 km from Fire Lake to Hart Jaune. Ontario Hydro extended its 500-kV line by 158 km from Nanticoke GS to Longwood TS (near London). New Brunswick Power completed its three 138-kV lines in 1991 and added 85 km to its system, linking

Table 9.2. Provincial interconnections at year-end, 1991

Connection	Voltage	Design Capability*
	(kV)	(MW)
British Columbia - Alberta	1 x 500	800
	1 x 138	110
Alberta - Saskatchewan	1 x 230	150
Saskatchewan - Manitoba	3 x 230	400
	2 x 110	100
Manitoba - Ontario	2 x 230	260
	1 x 115	
Ontario - Quebec	4 x 230	1 300
	7 x 120	
Quebec - Newfoundland	3 x 735	5 225
Quebec - New Brunswick	2 x ± 80(DC)	700
	2 x 345	
	2 x 230	300
New Brunswick - Nova Scotia	2 x 138	600
	1 x 345	
New Brunswick - P.E.I.	2 x 138	200

**Actual transfer capability in practice will be different from design capability.*

Source: Energy, Mines and Resources Canada.

Coleson Cove and Pennfield. Nova Scotia Power increased its 345-kV line by 43 km linking Onslow and Hopewell. Other in-province transmission line additions were made in Prince Edward Island and Alberta.

Presently, there are 14 in-province transmission lines under construction ranging from 138-kV to 500-kV, with a total circuit length of about 1206 km. Nova Scotia Power has two 138-kV lines and one 345-kV line under construction, connecting Hopewell and Woodbine, Point Aconi and Trenton, and Onslow and Hopewell. These three lines will add 292 km to Nova Scotia Power's system. New Brunswick Power's Belledune coal-fired station is expected to be in service in 1993. There are two 345-kV lines under construction, connecting Belledune, Bathurst, and Salisbury.

Hydro-Québec is building a 450-kV line linking Grondine to Lotbinieres under the St. Laurence River. Total circuit length for this under water line is 5 km.

Ontario Hydro is in the process of adding four more 500-kV lines. Two will connect the Lennox oil-fired station (near Kingston) with Bowmanville and Hawthorne, and the remaining two are linking Cherrywood, Nanticoke, and Chaireville. There will also be an additional 230-kV line linking the Porcupine transformer station near Timmins with Ansonville. These new lines will increase Ontario's total circuit length by 519 km.

In Saskatchewan, two 230-kV lines presently under construction will connect the Shand coal-fired station with Peebles, and Brada with Lloydminster. The total circuit length will be 260 km.

INTERPROVINCIAL TRANSMISSION

To facilitate energy exchanges and enhance the reliability of electrical systems operation, there are now 36 major provincial interconnections, with a total design capability of about 10 145 MW (Table 9.2). No provincial interconnection was added in 1991.

Presently, two provincial interconnections are being planned: one is a 500-kV line linking the Quebec Outaouais with Ottawa, a total circuit length of 51 km, and the other is a 500-kV line from Winnipeg to Dryden, Ontario, with a circuit length of 300 km. The estimated power transfer capability of each is about 1200 MW (Table 9.3).

INTERNATIONAL TRANSMISSION

Interconnections play a major role in modern power systems. Most Canadian utilities have both east-west and north-south lines that allow exchanges of power and energy. No international interconnection was completed in 1991.

There are now over 100 international transmission lines in place to provide for Canada's international electricity trade. Although most of these lines are quite small, there are 37 bulk power interties rated at 69-kV or higher, with a total power transfer capability of 18 900 MW (Table 9.4).

Table 9.3. Planned provincial interconnections

Province	Voltage	Estimated Power Transfer Capability	Completion Date	Status
	(kV)	(MW)		
Quebec - Ontario	500	1 200	2000	Proposed
Manitoba - Ontario	500	1 200	1999	Proposed

Source: Canadian Electric utilities.

B.C. Hydro is in the process of planning three 230-kV international transmission lines. The new lines will increase B.C. Hydro's total firm power transfer capability by about 900 MW. The lines are expected to be in service by 1996. Ontario Hydro is also planning to build a 115-kV line from Fort Frances TS to International Falls. The transfer capability is estimated to be 100 MW.

LONG-DISTANCE TRANSMISSION

Canada is a world leader in long-distance electric power transmission, in both extra-high-voltage (EHV) alternating

Table 9.4. Major interconnections between Canada and the United States, 1991*

Province	State	Voltage	Design Capability***
		(kV)	(MW)
New Brunswick	Maine	1 x 345	600
		1 x 138	60
		5 x 69	155
Quebec	New York	1 x 765	2 300
	New York	2 x 120	300
	Vermont	3 x 120	375
	New Hampshire	± 450(DC)	2000
Ontario**	New York	1 x 230	470
		1 x 230	400
		2 x 230	600
		2 x 345	2 300
		2 x 69	132
		2 x 115	200
	Michigan	1 x 230	535
		1 x 230	515
		2 x 345	1 470
	Minnesota	1 x 120	35
Manitoba	North Dakota	1 x 230	150
	Minnesota	1 x 230	175
	Minnesota	1 x 500	1 000
Saskatchewan	North Dakota	1 x 230	150
British Columbia**	Washington	1 x 230	300
		1 x 230	400
		2 x 500	4 300

** 35 MW capacity or over.*

*** The transfer capability of several lines may not be equal to the mathematical sum of the individual transfer capabilities of the same lines.*

**** Actual transfer capability in practice will be different from design capability.*

Source: Energy, Mines and Resources Canada.

current and HVDC. A major influence on the development of Canada's expertise in these areas has been the country's abundant water power resources. Early in the century, pioneering efforts in high-voltage transmission resulted in the initial development of hydroelectric power at Niagara Falls to supply the growing needs of communities in southern Ontario. In Quebec, the first 50-kV transmission lines were constructed to bring power from Shawinigan to Montreal.

After the harnessing of the major hydroelectric sites close to load centres, it became necessary to develop remote hydroelectric sources in several provinces and to integrate these sources into the power system over long-distance EHV and HVDC transmission lines. In 1965, Hydro-Québec installed the world's first 735-kV class transmission system. This system now extends over 1100 km from the Churchill Falls development in Labrador to Montreal. A comparable system of about the same distance extends from the James Bay development to Quebec's load centres.

In Manitoba, pioneering work was done to develop the ± 450-kV HVDC system, which now brings hydroelectric power from the Nelson River generating stations to customers in southern Manitoba. Ontario and British Columbia also have extensive EHV systems in the 500-kV class (Figure 9.1).

Such advances in Canadian transmission techniques have provided not only for long-distance bulk transmission, but also for extensive interconnections between neighbouring provinces and between Canada and the United States (Figure 9.2).

Figure 9.1. Canada's major long-distance transmission systems, 1991

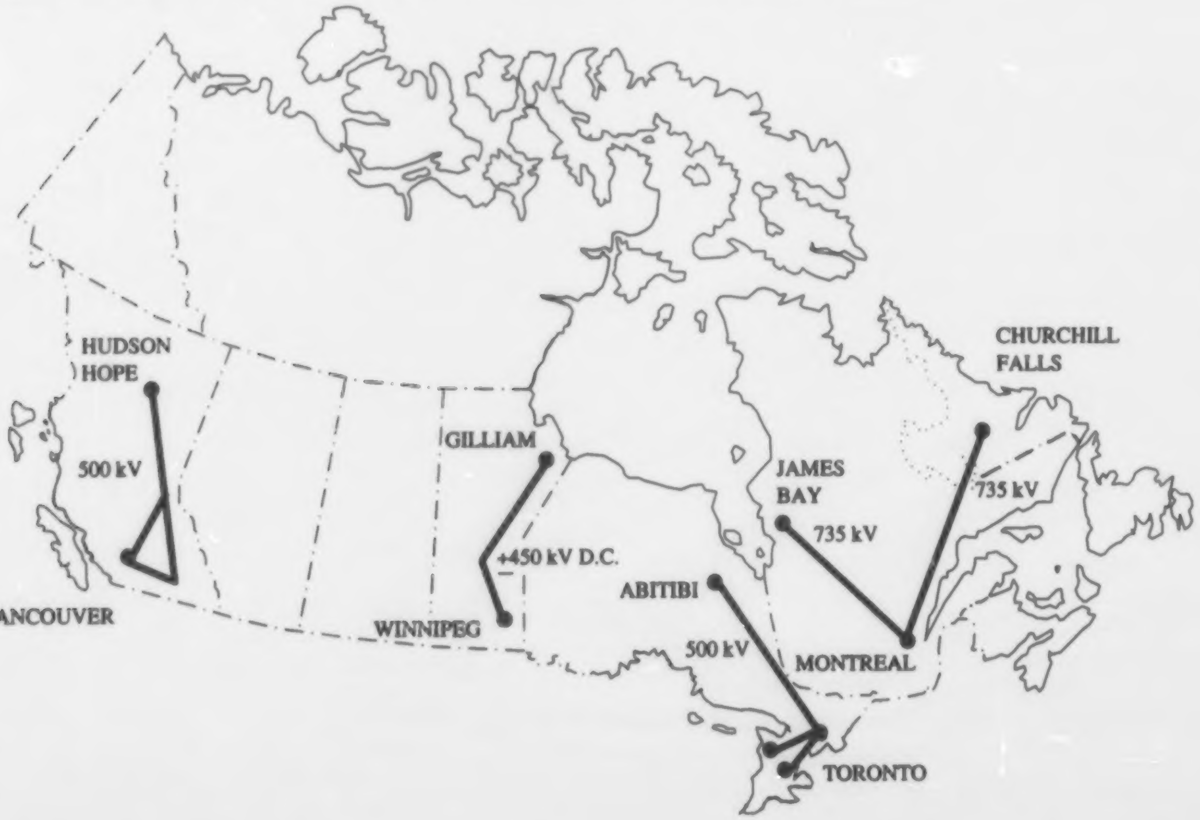
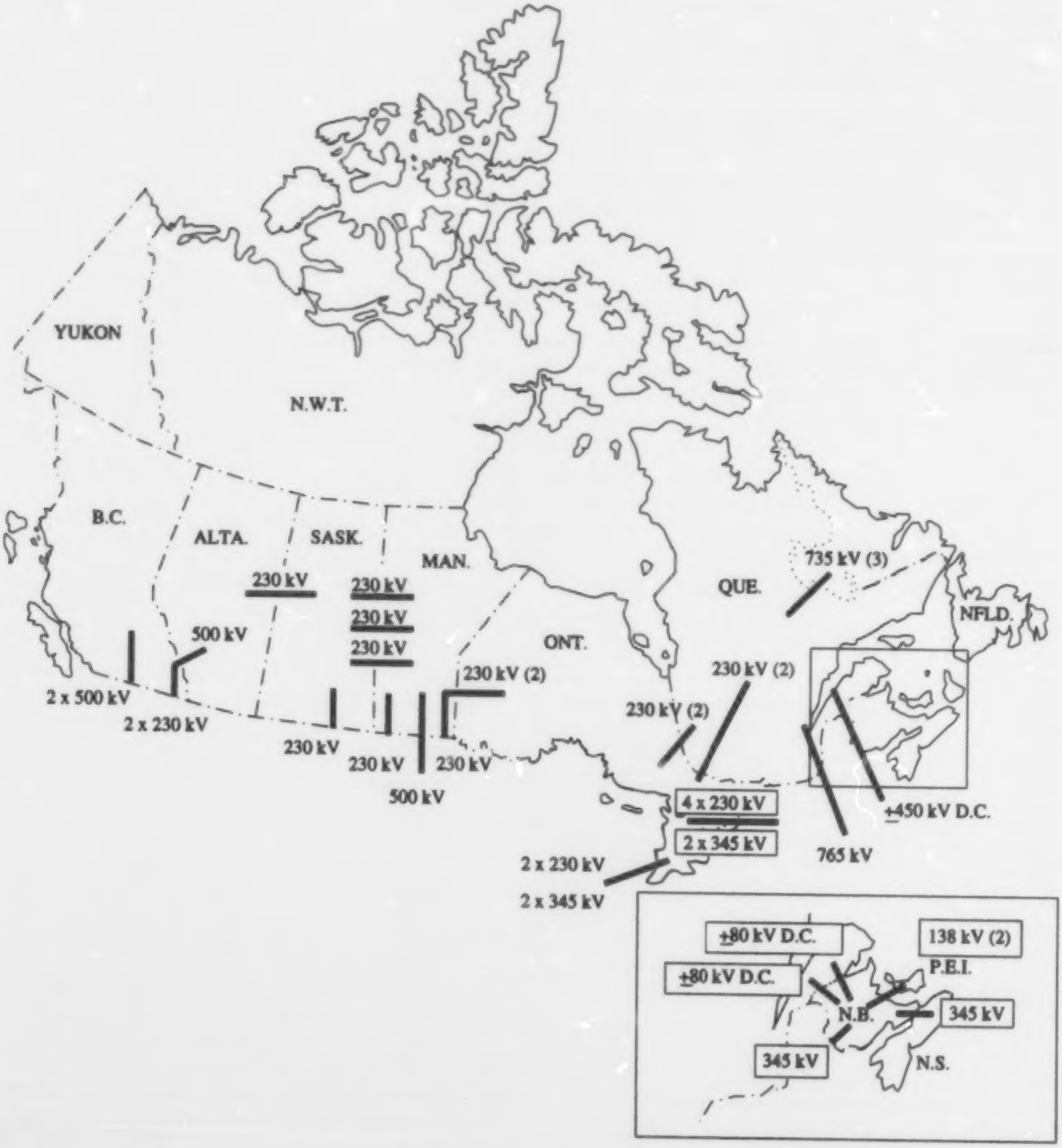


Figure 9.2. Major provincial and international interconnections, 1991


YUKON
N.W.T.
B.C.
ALTA.
SASK.
MAN.
ONT.
QUE.
NFLD.
735 kV (3)
230 kV
230 kV
230 kV
230 kV
500 kV
2 x 500 kV
2 x 230 kV
230 kV
230 kV
500 kV
230 kV
230 kV (2)
230 kV (2)
230 kV (2)
4 x 230 kV
2 x 345 kV
2 x 230 kV
2 x 345 kV
765 kV
±450 kV D.C.
±80 kV D.C.
±80 kV D.C.
138 kV (2)
P.E.I.
N.B.
345 kV
345 kV
N.S.

10. ELECTRIC UTILITY INVESTMENT AND FINANCING

CAPITAL INVESTMENT

The electric power industry is one of the most capital intensive industries in our economy. Between 1980 and 1991, the average capital-output ratio for the industry was 6.8 This means that in order to generate one dollar's worth of electricity, about seven dollars must be invested in the electric power industry. This capital-output ratio is very high, compared with 1.2 for total manufacturing industries, and 1.6 for the economy as a whole.

The most capital intensive type of electrical generation is nuclear. It is estimated that the capital cost of nuclear generation, including depreciation, the debt guarantee fee and financing charges, accounts for about 65 per cent of the total cost. The fuel cost accounts for only 14 per cent, and operation and maintenance for 21 per cent. Because of such a cost structure, nuclear energy is inflation proof over its 40-year life-service.

Every year, electric utilities make investments in new facilities or upgrade old facilities to meet their customers' needs. From 1971 to 1991, electric utilities total capital investments increased from about $1.8 billion to $11.5 billion, with an average annual growth rate of 10 per cent. With the removal of inflation of 4.9 per cent (measured by the implicit price deflator of gross fixed capital formation), this represents a real increase of about 5.1 per cent. Table 10.1 illustrates the capital-intensive nature of electricity generation and its importance in the Canadian economy. Due to

Table 10.1. Electric utility capital investment, 1971-1991

	Investment in electric power industry ($ million)	Utility investment as a percentage of total energy investment	Utility investment as a percentage of total investment in the economy	Utility investment as a percentage of GDP
1971	1 747	52	8	1.8
1972	1 754	49	7	1.6
1973	2 244	53	8	1.8
1974	2 753	53	8	1.8
1975	3 957	58	9	2.3
1976	4 229	55	9	2.1
1977	4 884	56	10	2.2
1978	5 936	58	11	2.5
1979	6 364	53	10	2.3
1980	6 109	42	8	2.0
1981	7 319	40	9	2.1
1982	8 408	39	10	2.2
1983	7 770	42	10	1.9
1984	6 340	37	8	1.4
1985	5 727	34	6	1.2
1986	5 618	41	6	1.1
1987	5 946	45	6	1.1
1988	6 971	44	7	1.2
1989	8 863	51	8	1.4
1990	10 728	51	7	1.6
1991	11 461	51	9	1.7

Source: Energy, Mines and Resources Canada.

Table 10.2. Investment in energy-related industries, 1972-1991

Year	Petroleum and Natural Gas Exploration and Production	Refining and Marketing	Natural Gas Processing Plants & Distribution	Pipelines	Electric Power	Coal Mines & Products	Uranium Mines	Drilling Contractors	Total
	(millions of dollars)								
1972	666	351	272	447	1 754	42	11	24	3 567
1975	1 390	601	341	362	3 957	123	30	27	6 831
1980	5 745	509	698	602	6 109	306	277	198	14 444
1985	8 187	685	942	665	5 727	475	160	80	16 921
1986	5 401	733	782	587	5 618	434	144	30	13 729
1987	4 415	1 062	746	503	5 946	338	113	13	13 136
1988	5 590	1 149	875	829	6 971	345	139	17	15 915
1989	4 310	1 443	997	1 183	8 863	312	105	14	17 227
1990	4 751	1 382	1 112	1 817	10 728	337	138	12	20 277
1991	5 116	1 447	1 446	2 706	11 461	368	66	13	22 623

Source: Energy, Mines and Resources Canada.

Table 10.3. Capital investment by function, 1972-1991

Year	Generation	Transmission	Distribution	Other	Total
		(millions of current dollars)			
1972	1 020	432	229	73	1 754
1975	2 460	616	547	334	3 957
1980	3 580	1 114	703	712	6 109
1985	2 941	836	1 008	942	5 727
1986	3 214	815	989	600	5 618
1987	2 774	1 200	1 039	933	5 946
1988	3 137	1 812	1 115	907	6 971
1989	4 520	2 216	1 330	797	8 863
1990	6 408	2 162	1 287	871	10 728
1991	6 145	2 472	1 355	1 489	11 461

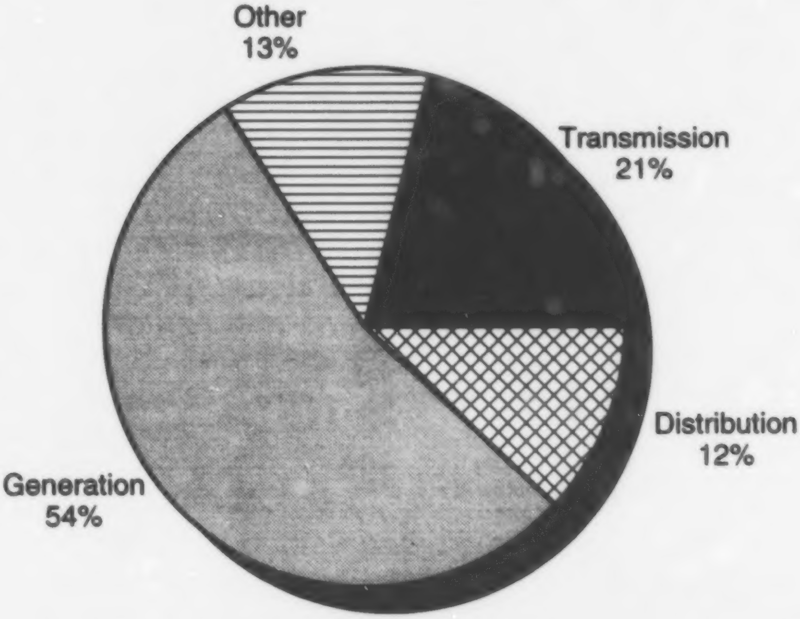
Source: Energy, Mines and Resources Canada.

stronger-than-expected domestic demand in the past three years, electric utilities increased their capital spending by more than $1 billion in 1988, and about $2 billion each in 1989 and 1990. However, capital expenditures from electric utilities increased only $700 million in 1991 because of the economic recession and a shift of some investments to demand- side management programs.

Table 10.2 summarizes capital expenditures in the energy sector. During the period 1972-91, the electric power industry had the largest investment share in the energy sector, with the exceptions of 1984 and 1985, when petroleum and natural gas exploration and production had the largest share. Over the past 20 years, capital investment in the electric power industry has totalled about $123 billion (accounting for 50 per cent of total investment in the energy sector). In 1991, the electric power industry's investment share was 51 per cent of the total for the energy sector, the same as in 1989 and 1990, indicating that the electric power industry may be returning to the high investment period of the 1970s (Table 10.1).

Of the total $123 billion capital investment between 1972 and 1991, about 57 per cent was for generation, 19 per cent for transmission, 13 per cent for distribution, and 11 per cent for other (Table 10.3). This represents a fairly large investment in generation for the period, since a traditional rule-of-thumb states that capital investment in generation normally accounts for 50 per cent of total investment in the industry. Figure 10.1 shows electric utility capital investment by function in 1991.

Figure 10.1. Capital investment by function, 1991



Total Investment: $11.5 billion

Table 10.4 reports the capital investment for 15 major electric utilities in 1990 and 1991. With the exceptions of Newfoundland and Labrador Hydro, Newfoundland Light & Power, Alberta Power, and the Northwest Territories Power Corporation, all major utilities increased their capital investment in 1991. Ontario Hydro continued to be the largest money spender, accounting for 38 per cent of total utility capital investment in 1991, most of which was related to the on-going construction of the Darlington nuclear station.

CAPITAL FINANCING

To build a power project, an electric utility normally uses its reserve funds to finance a portion of the construction cost (self-financing). But a large portion of the project cost is financed by international and domestic debt borrowings (debt-financing) and bond and/or stock issues (equity-financing). Electric utilities regularly have to pay a fixed interest charge on debt-financing, while the payments on equity-financing, especially stock issues, are determined by the operation of the utility.

Canada's electric utilities rely heavily on foreign sources to finance their capital investment because of a relatively small financial market within the country. However, the degree of dependence on foreign financing has been reduced substantially since 1986. Some major electric utilities have tried to finance their power projects mainly from domestic financial markets in order to avoid foreign exchange losses. In 1985, foreign financial sources accounted for 52 per cent of the existing total long-term debt financing. This percentage was reduced to 46 in 1986, 43 in 1987, 40 in 1988, and 32 in 1989. As of December 31, 1990, the total outstanding long-term debt of major electric utilities in Canada was about $76 billion. Of this total, about 65 per cent (or $50 billion) was borrowed on the domestic market, and 35 per cent (or $26 billion) on international markets. Of the total $26 billion borrowed internationally, it is estimated that 79 per cent (or $20.6 billion) was raised in the United States; 5 per cent (or $1.3 billion) in West Germany; 4 per cent (or $1.1 billion) in Switzerland; 2.3 per cent (or $806 million) in the United Kingdom; and 2 per cent (or $412 million) in Japan (Table 10.5).

In Canada and the United States, publicly owned electric utilities depend mainly on debt-financing. Investor-owned utilities, on the other hand, rely much more on equity-financing. Table 10.6 indicates that in 1990 Canadian publicly owned electric utilities had debt ratios ranging from 69 per cent to 96 per cent. With the exceptions of Nova Scotia Power and Manitoba Hydro, all publicly owned utilities have strong financial positions. The debt ratios for investor-owned utilities ranged from 39 per cent to 46 per cent, indicating they are also financially sound.

High debt ratios, similar to those of Canadian publicly owned utilities, were also common among government-owned

Table 10.4. Capital investment by major electric utility

	1990	1991	Year-over-year change
		(millions of current dollars)	
Newfoundland and Labrador Hydro	75	44	-31
Newfoundland Light & Power	65	47	-18
Maritime Electric Co. Ltd.	15	17	2
Nova Scotia Power	262	374	112
NB Power	500	600	100
Hydro-Québec	3 177	4 074	897
Ontario Hydro	3 700	4 200	500
Manitoba Hydro	475	487	12
Saskatchewan Power	291	365	74
Alberta Power	191	164	-27
Edmonton Power	158	250	92
TransAlta Utilities	264	280	16
B.C. Hydro	93	144	51
Yukon Energy Corporation	10	11	1
Northwest Territories Power Corporation	29	19	-10
Canada	9 305	11 076	1 771

Source: Energy, Mines and Resources Canada.

utilities in the United States. As Table 10.6 indicates, the Power Authority of the State of New York, the Tennessee Valley Authority, and the Bonneville Power Administration had debt ratios of 70, 84 and 100 per cent respectively. The selected American investor-owned utilities had debt ratios ranging from 39 per cent to 57 per cent in 1990. In general, the financial position of American investor-owned utilities is not as good as for their Canadian counterparts.

Table 10.5. Major electric utility long-term debt and sources of financing, 1990

	Long-Term Debt	Sources of Long-Term Debt Financing	
	($ millions)	Domestic (%)	Foreign (%)
Newfoundland and Labrador Hydro	1 398	76	24
Newfoundland Light & Power	158	95	5
Maritime Electric Co. Ltd.	36	100	0
Nova Scotia Power	1 769	92	8
NB Power	2 024	59	41
Hydro-Québec	25 632	45	55
Ontario Hydro	29 378	77	23
Manitoba Hydro	4 199	40	60
Saskatchewan Power	1 266	58	42
Alberta Power	855	100	0
Edmonton Power	1 128	100	0
TransAlta Utilities	1 470	98	2
B.C. Hydro	6 858	78	22
Yukon Energy Corporation	70	100	0
Northwest Territories Power Corp.	62	100	0
Canada	76 303	65	35

Source: Energy, Mines and Resources Canada.

Table 10.6. Comparison of Canadian and U.S. electric utility debt ratios, 1985-1990

	1985	1986	1987	1988	1989	1990
CANADA			(per cent)			
Publicly owned utilities						
Newfoundland and Labrador Hydro	90	88	86	83	82	84
Nova Scotia Power	95	96	98	99	97	96
NB Power	88	84	85	83	82	83
Hydro-Québec	76	76	75	74	74	75
Ontario Hydro	84	84	84	83	83	83
Manitoba Hydro	96	96	97	98	97	96
Winnipeg Hydro	68	71	72	75	69	75
Saskatchewan Power	87	88	87	81	74	69
Edmonton Power	80	75	75	75	76	73
B.C. Hydro	86	88	86	81	80	79
Investor-owned utilities						
Newfoundland Light & Power	45	43	48	44	48	43
Maritime Electric Co. Ltd.	43	42	43	47	47	39
TransAlta Utilities Corporation	33	38	35	39	41	45
Alberta Power	29	32	39	38	41	46
UNITED STATES						
Publicly owned utilities						
Tennessee Valley Authority	83	83	83	83	81	84
Bonneville Power Administration	100	100	100	100	100	100
Power Authority of the State of New York	71	72	74	69	68	70
Investor-owned utilities						
Boston Edison Company	51	46	48	50	52	55
Northeast Utilities	53	52	53	54	52	51
Consolidated Edison Company of New York	36	36	37	37	38	39
Niagara Mohawk Power Corporation	46	47	55	55	57	57
American Electric Power Company	53	53	54	52	47	50
Northern States Power Company	46	46	43	42	41	41
Washington Water Power Company	44	48	48	51	49	47
Pacific Gas and Electric Company	48	46	49	49	48	48

Source: Energy, Mines and Resources Canada.

11. COSTING AND PRICING

ELECTRICITY SUPPLY COSTS

During the past 30 years, increases in the cost of building electric power stations, transmission lines, and distribution systems have been relatively small, with the exception of the period 1973-81, which coincided with the first (1973) and second (1979) oil crises (Table 11.1).

The unit cost of supplying additional electricity increased rapidly during the period

Table 11.1. Inflation, interest rates and construction costs, 1962-1991

	Average Interest Rate	Increase in Construction Costs					
		Hydro	Steam	Nuclear	Transmission	Distribution	CPI
				(per cent)			
1962	5.4	2.8	-	-	1.0	1.8	1.2
1963	5.5	3.3	-	-	1.5	0.4	1.7
1964	5.5	3.2	-	-	0.0	2.2	1.8
1965	5.7	5.0	-	-	5.7	2.2	2.5
1966	6.4	6.2	-	-	4.1	5.1	3.7
1967	6.7	3.6	1.1	-	5.2	1.6	3.5
1968	7.8	4.2	2.8	-	2.9	1.2	4.7
1969	8.6	5.7	6.8	-	4.4	4.3	4.5
1970	9.3	6.6	7.4	-	5.0	7.5	3.3
1971	8.5	4.6	6.0	-	5.5	3.5	2.9
1972	8.4	6.3	6.1	6.9	6.3	4.4	4.8
1973	8.6	9.2	9.2	9.5	8.8	9.4	7.6
1974	10.2	18.8	20.5	19.2	19.2	20.4	10.9
1975	10.7	14.3	13.4	13.1	17.6	12.3	10.8
1976	10.4	8.9	10.0	9.7	7.3	5.7	7.5
1977	9.6	5.9	7.9	7.5	7.8	6.6	8.0
1978	10.1	7.7	8.7	8.0	8.0	7.4	9.0
1979	10.9	8.7	11.0	12.7	14.8	13.5	9.2
1980	13.3	10.0	11.6	22.0	13.6	14.0	10.2
1981	16.3	13.7	11.9	11.4	11.3	9.1	12.5
1982	15.9	7.2	6.8	5.3	4.8	9.3	10.8
1983	12.7	4.6	4.1	5.0	3.8	4.1	5.8
1984	13.5	3.2	2.8	0.1	5.3	4.4	4.4
1985	11.7	1.7	3.8	4.8	0.9	5.2	4.0
1986	10.4	4.1	3.5	3.5	2.1	2.4	4.1
1987	10.7	4.1	3.0	1.9	3.8	3.1	4.4
1988	10.9	4.0	5.7	2.8	9.2	6.1	4.1
1989	10.8	3.4	4.2	5.1	3.6	3.8	5.0
1990	11.9	4.5	3.6	3.3	2.6	3.2	4.8
1991	10.8	2.5	2.3	1.8	-1.7	-0.9	5.6

Source: Interest rates - McLeod Young Weir Limited's average corporate bonds yield.
Construction costs and CPI - Statistics Canada publications 62-007 and 62-001.

1973-81. There were two key reasons for the rapid increases in the cost of electricity: the high rate of inflation (as measured by the CPI or the GDP deflator), with an average increase of 9.5 per cent; and the increased cost of fossil fuels, with an average annual increase of 15 per cent. In general, high levels of inflation affect the electric utility industry by increasing the cost of constructing additional facilities and by increasing the cost of borrowed funds.

The average interest rate on long-term utility debt for the period 1962-91 is also shown in Table 11.1. Interest rates started to rise after the first oil crisis, and reached a peak of 16.3 per cent in 1981. After this they dropped steadily to about 10.8 per cent by 1989, 11.9 per cent by 1990, and 10.8 per cent by 1991.

Since 1982, construction cost increases have moderated significantly. Adjusted for inflation, recent increases in the supply cost of electricity have been very small, or negative. Starting in 1991, the Federal Sales Tax was removed from

Table 11.2. Cost of fuel for electricity generation, 1969-1990

	Eastern Coal*	Western Coal**	Petroleum	Natural Gas	Uranium	Total Fuels
			(mills/kW.h)			
1969	3.46	1.11	4.97	2.54	-	3.24
1970	3.60	1.38	5.68	2.47	-	3.25
1971	4.20	1.28	5.98	3.15	-	3.46
1972	4.32	1.34	6.41	3.93	-	3.42
1973	4.65	1.43	7.06	3.74	-	3.13
1974	5.38	1.54	11.36	5.18	-	4.10
1975	8.64	2.07	12.87	7.17	-	6.16
1976	11.43	2.97	15.38	11.74	1.14	8.11
1977	11.89	3.20	19.01	15.21	1.34	8.40
1978	13.12	2.88	21.22	16.19	1.61	8.82
1979	16.50	3.11	23.93	15.22	1.65	9.62
1980	18.22	3.75	26.22	15.47	2.65	10.69
1981	20.48	4.83	40.77	23.22	2.68	12.22
1982	22.61	5.76	44.88	30.16	2.87	14.04
1983	23.71	5.96	57.27	31.17	3.25	13.20
1984	24.85	5.94	65.11	34.15	3.84	13.64
1985	26.07	6.59	68.02	31.81	4.74	13.54
1986	25.88	5.13	45.15	27.11	4.52	10.70
1987	25.07	5.84	37.22	22.20	4.77	11.63
1988	22.05	5.51	27.53	25.17	4.53	10.52
1989	20.96	5.63	29.08	18.78	4.62	11.16
1990	22.83	5.87	32.93	21.67	4.88	11.41

* *Nova Scotia, New Brunswick and Ontario.*
** *Alberta, Saskatchewan and Manitoba.*

Source: Calculated from Electric Power Statistics, Statistics Canada, catalogue 57-202, various issues.

items where it had previously been deemed applicable. The Goods and Services Tax is not applied to any item within the electric utilities construction; if utilities pay GST on their construction inputs, they are later reimbursed.

Table 11.2 summarizes the unit costs of the various fossil-fuels used for electricity generation. Like construction costs, unit fuel costs increased substantially during the period 1973-81. It is estimated that the cost of natural gas increased annually by an average of 30 per cent, petroleum by 23 per cent, eastern coal by 19 per cent, and western coal by 15 per cent.

Unit fossil-fuel costs reached a peak in 1985 but began to decline in 1986 with the collapse of world oil prices. By 1989 the unit costs of using natural gas and eastern coal for electricity generation were still declining. In 1990, all unit costs of electricity generation increased, particularly the costs of petroleum and natural gas. A 13 per cent increase of the petroleum price was mainly due to the Persian Gulf War which started in August of that year. The price of natural gas increased by 15 per cent. This was due to a reduction in natural gas use for electricity generation. Generally, electric utilities can bargain for a lower price if the demand for natural gas is high.

In 1989, 2621 GW.h of electricity exported to the United States (about 14 per cent of the total export) came from natural gas. All natural gas-based exports came from British Columbia, where B.C. Hydro had

Table 11.3. Average annual electricity rate increases, 1982-1991

	Rate Changes (%): Average of all Customer Classes									
	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991
Newfoundland and Labrador Hydro	-	18.2	-	-	-1.7	-	-	1.0	8.2	1.6
Newfoundland Light & Power	-	12.0	-	-	8.7	3.0	-1.1	2.0	12.5	0.8
Maritime Electric Co. Ltd.	-**	-**	-	3.7	-3.8	-	-1.3	-	5.5	5.3
Nova Scotia Power	-	-	-	-	-	-	-	6.3	2.5	5.0
NB Power	-	8.8	6.2	4.6	-	-	-	-	-	4.4
Hydro-Québec	16.3	7.3	4.0	4.0	5.4	4.9	3.9	4.7	7.4	7.0
Ontario Hydro	10.0	8.2	7.5	8.6	4.0	5.0	4.7	5.3	5.9	8.6
Manitoba Hydro	-	9.5	7.9	5.0	2.8	9.7	4.5	6.0	4.0	3.5
Saskatchewan Power	7.5	12.6	9.2	-	7.5	7.5	6.1	3.9	-1.9	-0.6
Edmonton Power	13.2	8.0	5.0	6.7	0	3.0	1.9	-	-	3.0
TransAlta Utilities	4.0	15.0	-	1.7	6.1	-1.8	-1.0	5.5	-1.1	12.0
Alberta Power	-11.6*	2	-	-4.3	-8.6	-5.0	14.5	2.6	3.7	17.0
B.C. Hydro	20.0*	6.0	65	3.8	1.8	-	-	3.0	1.5	3.0
Yukon Energy	-	-	-	-	0.7	-	-	-	4.0	11.3
NWT Electric	-	-	-	-	-	-	-	-	9.5	0
Weighted Canada	-	-	-	6.2	4.1	4.2	3.5	4.3	4.9	6.8

* *Based on residential category.*

** *Does not reflect monthly changes to the cost of commodity and fuel adjustment charges.*

Source: Energy, Mines and Resources Canada.

reactivated its Burrard natural gas-fired station to alleviate the reduced electrical output caused by low waterflow conditions in the province. B.C. Hydro got a good deal in the purchase of natural gas.

The unit cost of fuel generated from coal varies between regions of the country. It depends on the type of coal used, its source, and the percentage of total energy supply derived from fossil-fuel plants. The unit fuel cost of electricity generated from western Canadian coal increased from 1.11 mills per kw.h in 1969 to 5.87 mills per kw.h in 1990. In the same period, the cost of coal-fired generation in eastern Canada increased from 3.46 mills per kw.h to 22.83 mills per kw.h. This large cost-difference between the two regions is mainly due to the fact that coal used for electricity generation in western Canada is produced domestically, while a large proportion of the coal used in eastern Canada is imported.

Over the last 15 years, nuclear-generated electricity has had the lowest unit fuel cost in Canada. In 1990, it cost 4.88 mills per kw.h, compared with 32.93 mills for petroleum, 21.67 mills for natural gas, 22.83 mills for eastern coal, and 5.87 mills for western coal. However, in terms of percentage increases, the unit fuel cost of using uranium for electricity generation increased at an average annual rate of 10 per cent during the period 1976-90, compared with 6 per cent for petroleum, and 5 per cent each for eastern coal, western coal and natural gas.

ELECTRICITY PRICING

In Canada, electric utilities price electricity at the average cost of production, which is generally lower than the marginal cost of production. Although marginal-cost pricing of electricity has the advantage of achieving economic efficiency (i.e. closing the cost-price gap), this pricing method has not been adopted by the electric utilities because of the complexity of the marginal pricing scheme. Also, historically, utilities and low-cost electricity have been seen as tools of provincial economic

Table 11.4. Average revenue from electricity sales by province, 1981-1990

	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
					(current cents/kW.h)					
Nfld.	2.8	3.6	3.7	3.9	4.7	3.9	4.0	4.0	4.1	4.4
P.E.I.	10.0	12.0	12.3	12.8	12.9	11.5	10.3	10.8	10.2	10.8
N.S.	4.9	5.9	6.9	7.5	7.3	6.9	6.8	7.0	6.9	7.2
N.B.	4.8	5.1	5.4	5.5	5.8	5.5	5.5	5.3	5.5	5.2
Que.	2.6	3.1	3.4	3.4	3.5	3.4	3.4	3.6	3.9	4.3
Ont.	3.2	3.6	3.9	4.2	4.5	4.5	4.9	5.1	5.4	5.7
Man.	2.8	2.9	3.1	3.4	3.6	3.6	3.9	4.0	4.1	4.3
Sask.	3.6	4.0	4.2	4.5	4.8	5.0	5.5	5.8	6.1	6.0
Alta.	4.1	4.9	5.2	5.4	5.4	5.4	5.3	5.0	4.9	5.2
B.C.	3.0	3.8	3.8	4.1	4.4	4.2	4.2	4.2	4.2	4.3
Yukon	6.7	8.3	8.3	8.6	9.0	7.8	7.4	7.7	7.1	7.3
N.W.T.	11.5	14.8	17.9	16.7	16.3	15.9	17.6	17.7	20.7	19.9
Canada	3.1	3.7	3.9	3.9	4.1	4.3	4.2	4.5	4.8	5.0

Source: Statistics Canada publication 57-202.

development. However, rate design has improved since the first oil crisis of 1973, and several alternatives to marginal-cost pricing have been implemented. For example, declining block rates for residential users (i.e. the more you use the less you pay) have been replaced by a uniform rate in Newfoundland, Prince Edward Island, Saskatchewan, Alberta and the Yukon; seasonal time-of-use rates were introduced in Ontario in January 1989; and automatic adjustment clauses for the escalation of fuel costs have been built into the rate design of those utilities that operate baseload oil-fired stations. The objective of all of these rate design efforts is to close the cost-price gap.

Table 11.3 presents annual electricity rate increases for major electric utilities across Canada over the past 10 years. In 1991, Alberta Power had the highest rate increase with 17 per cent, followed by TransAlta Utilities with 12 per cent. Ontario Hydro had a moderate rate increase with 8.6 per cent, and Hydro-Québec with 7 per cent. A weighted average for

Table 11.5. Major electric utilites' statements of income, 1991

	Total Revenue	O&M	Fuel Costs	Power Purchased	Depreciation	Taxes	Interest	Exchange Losses	Other Costs	Net Income
	(millions of current dollars)									
Newfoundland and Labrador Hydro	370	97	58	1	36	-	148	-	-	30
Newfoundland Light & Power	329	56	-	184	25	15	21	-	-	28
Maritime Electric Company Limited	77	31	-	21	6	6	6	-	-	7
Nova Scotia Power	636	140	221	16	63	5	167	-	-	24
NB Power	909	132	325	114	106	-	204	-	20	8
Hydro-Québec	6 284	1 870	-	184	737	392	2 294	47	-	760
Ontario Hydro	7 143	2 037	1 128	151	1 136	252	2 234	7	(6)	204
Manitoba Hydro	703	254	-	18	93	33	257	-	-	48
Winnipeg Hydro	118	34	-	52	3	1	10	-	1	17
Saskatchewan Power	674	213	127	-	97	-	119	-	-	118
Alberta Power	462	113	62	-	60	69	92	-	(35)	101
Edmonton Power	367	85	-	48	42	29	80	-	-	83
TransAlta Utilities	1 001	212	-	81	195	180	168	-	(50)	215
B.C. Hydro	1 909	339	296	-	229	99	739	-	-	207
Yukon Energy Corporation	22	11	-	-	3	-	4	-	-	4
Northwest Territories Power Corporation	90	41	32	-	9	-	8	-	(2)	2
Canada	21 094	5 665	2 249	870	2 840	1 081	6 551	54	(72)	1 856

Source: Obtained from electric utilities' annual reports, 1989.

Canada was about 6.8 per cent, compared with 4.9 per cent in 1990. Both increases were in line with the CPI, which registered increases of 4.8 per cent in 1990 and 5.6 per cent in 1991.

The average revenue from electricity sales for each province is provided in Table 11.4. Because electricity rates are regulated by provincial governments and are intended to cover a utility's costs, rate increases tend to parallel the rate of inflation. The average annual growth in unit revenue for Canada as a whole was 5.5 per cent during the period 1981-90. The national inflation rate, as measured by the CPI, was 5.9 per cent over the same period.

Income statements for the major electric utilities are summarized in Table 11.5. In 1991, 16 major electric utilities in Canada had a total operating revenue of $21.1 billion, with a net income of $1.9 billion. Hydro-Québec had the largest net income of $760 million, followed by TransAlta Utilities with $215 million, and B.C. Hydro with $207 million. Ontario Hydro's net income for 1991 came to $204 million, an increase of $75 million over the 1990 level of $129 million, but still much smaller than $699 million registered in 1989. High interest charged to operations in 1991 was the main factor contributing to the relatively low net income for Ontario Hydro.

Electricity costs differ across the country primarily because of differences in generation mix, the size of the utility and its market, indigenous resources, and the geographic distribution of the population being served. Table 11.6 gives typical monthly electricity bills for selected Canadian cities as of January 1991. Winnipeg had the lowest electricity cost in the residential sector, Vancouver in the

Table 11.6. Monthly electricity costs, January 1992 (Dollars)*

Sector: Billing Demand (kW): Consumption (kW.h):	Residential - 1000	Commercial 100 25 000	Industrial 1000 400 000
St. John's	86	2 562	24 088
Charlottetown	115	3 185	34 831
Halifax	90	2 705	26 456
Fredericton	72	1 754	21 360
Montreal	63	2 215	21 141
Ottawa	73	1 903	25 591
Toronto	94	2 674	31 710
Winnipeg	61	1 706	18 411
Regina	76	2 438	29 112
Saskatoon	76	2 435	27 191
Calgary	69	1 943	21 824
Edmonton	63	1 978	22 780
Vancouver	73	1 620	18 414
Whitehorse	83	3 003	-
Yellowknife	135	3 410	-

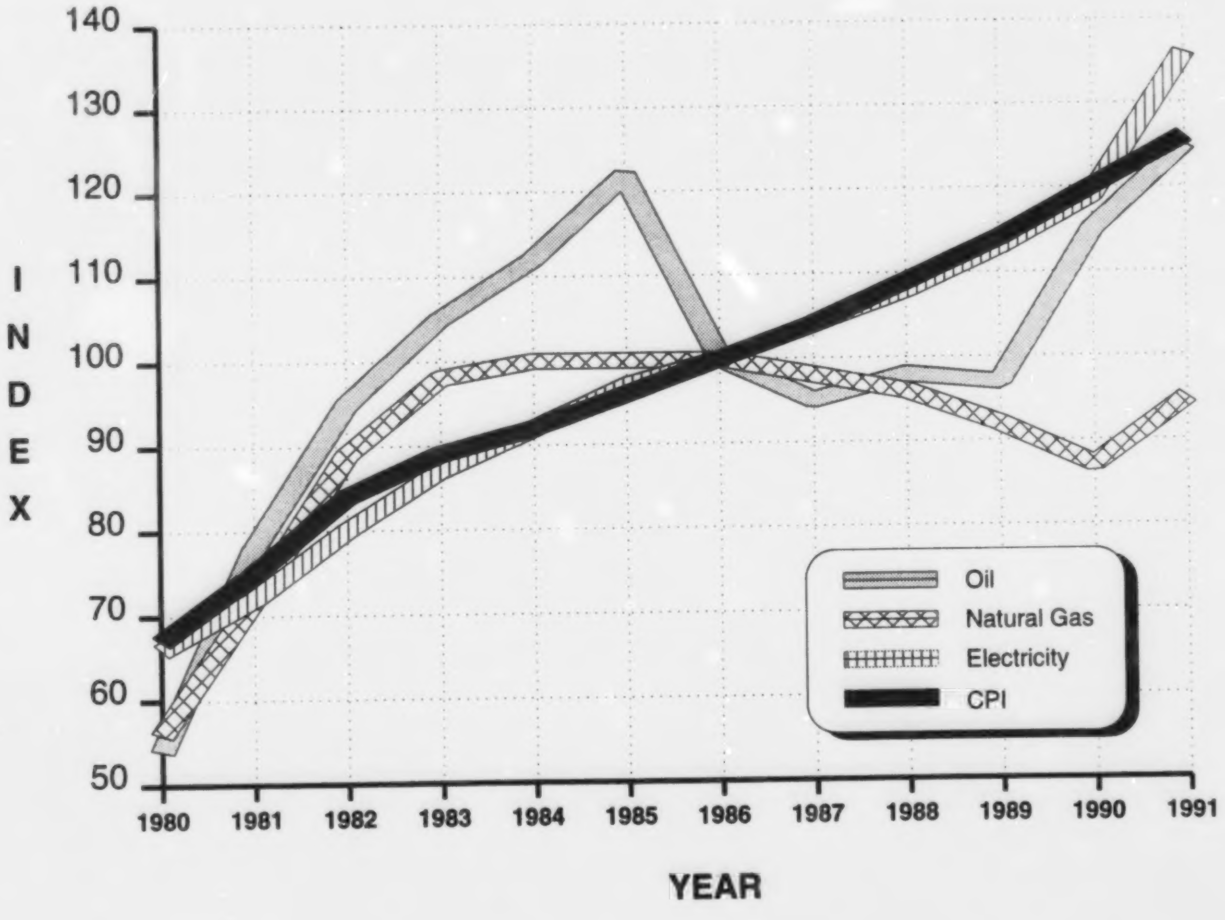
** Bills computed include sales tax, discounts and subsidies.*

Source: Energy, Mines and Resources Canada.

commercial sector, and Winnipeg in the industrial sector.

Figure 11.1 illustrates the movement of the electricity, oil and natural gas components of the CPI, as well as the CPI itself. It indicates that, since the collapse of world oil prices in 1986, the electricity price component has increased in line with the CPI, while natural gas price indices have declined despite rising inflation. The oil price indices have also decreased since 1986, but started to rise in 1990 and 1991.

Figure 11.1. Price indices, 1980-1991



12. ELECTRICITY OUTLOOK

Forecasting electricity demand has become a difficult task in recent years. This is largely a result of the economic dislocation caused by rapidly rising energy prices, particularly between 1975-77 and 1980-82. The effects of higher energy prices have been felt globally, and adjustments have been made worldwide in the amount, types and uses of energy. The collapse of world oil prices in 1986 added to the uncertainty, as did the 1990-91 recession. Adjustments in energy-use patterns continue to make economic forecasting difficult, which in turn, leads to uncertainty about future electricity demand because of its strong correlation with economic growth.

Despite this uncertainty, forecasts of electricity demand are essential to ensure that sufficient generating capacity is available when it is needed. The long lead-time in the construction of new generating facilities makes it necessary for electric utilities to calculate future demand many years in advance.

FORECASTS OF ENERGY DEMAND

Economic and population growth in Canada over the next 19 years are expected to be significantly lower than the previous 30-year period. It is estimated that the real Gross Domestic Product will grow at an average of only 2.4 per cent for the period 1991-2010, much less than the historical average of 4.1 per cent achieved during the past 30 years, while population is expected to grow at an average of 1.1 per cent for the period 1991-2010, less than 1.3 per cent registered during the period 1960-1991. It is also expected that the country's economic structure will not shift greatly over the same period from predominantly service-producing industries to goods-producing industries. Demand-side management is expected to have greater emphasis in future

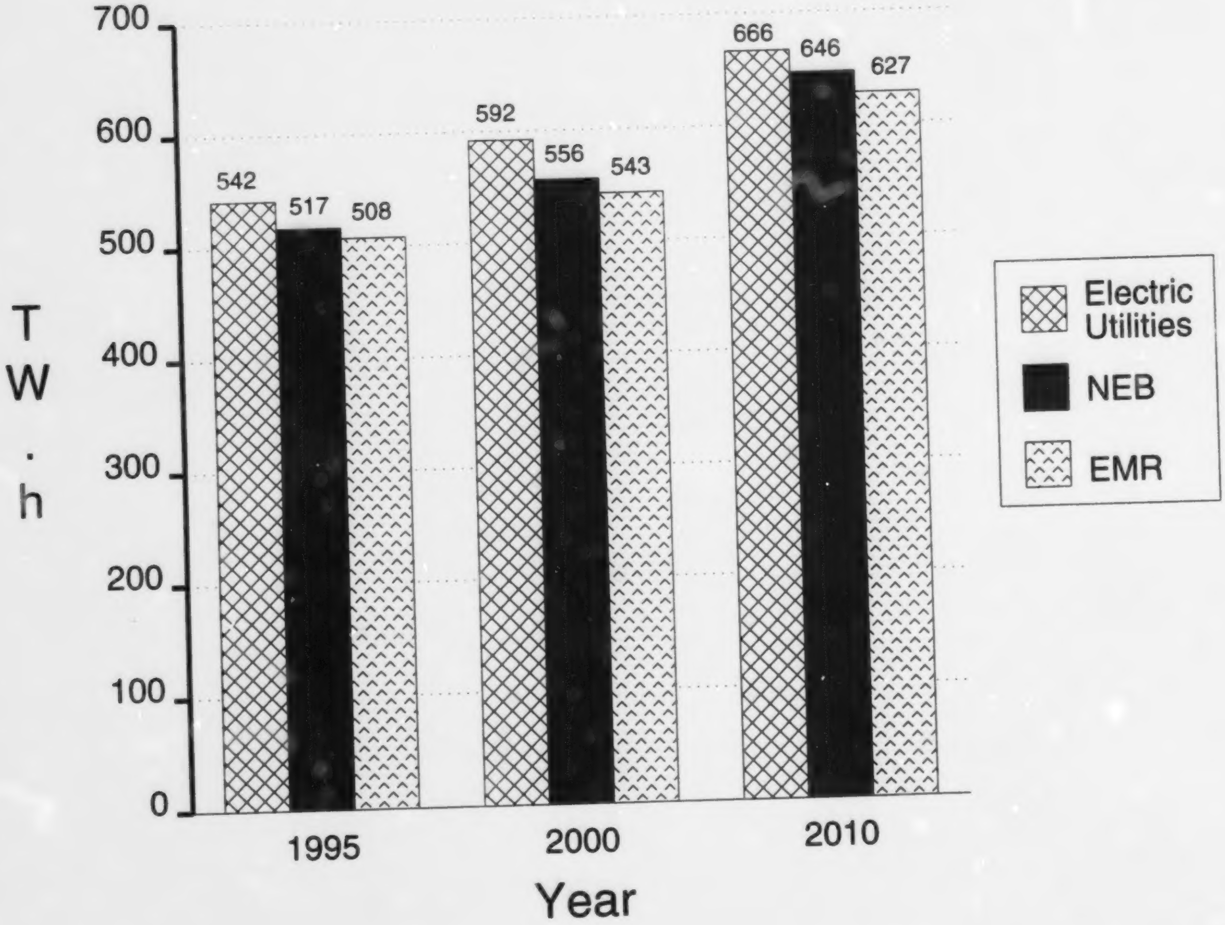
Table 12.1. Forecasts of domestic electricity demand

	1991*	1992	1995	2000	2005	2010	Average Annual Growth Rate 1991-2010
				(GW.h)			(%)
Nfld.	10 601	10 530	11 119	11 960	13 128	14 396	1.6
P.E.I.	761	766	812	920	1 059	1 222	2.5
N.S.	9 779	10 131	10 788	11 617	12 652	14 001	1.9
N.B.	13 638	14 582	15 550	17 551	19 769	22 278	2.6
Que.	160 803	170 289	192 289	213 289	217 479	228 579	1.9
Ont.	141 674	148 228	159 916	170 552	180 370	195 492	1.7
Man.	18 013	18 127	19 164	21 055	22 559	24 169	1.6
Sask.	13 818	14 896	16 202	17 457	18 409	19 324	1.8
Alta.	43 338	46 589	51 259	58 410	63 296	68 590	2.4
B.C.	57 528	59 165	63 525	68 300	72 330	76 430	1.5
Yukon	465	505	533	597	669	749	2.5
N.W.T.	477	527	550	569	586	606	1.3
Canada	470 895	494 335	541 707	592 277	622 306	665 836	1.8

* *Actual data.*

Source: Canadian electric utilities and National Energy Board.

Figure 12.1 Comparison of electricity demand forecasts



electrical planning. Because of these expectations, electricity demand is projected to grow at a slower rate. Table 12.1 summarizes electricity demand forecasts for the ten provinces and two territories. The projections of electrical energy demand within the service areas of the major electric utilities were prepared by the major utilities and provided to Energy, Mines and Resources Canada (EMR) in March 1992. Electricity demand for smaller utilities and industrial establishments was projected by the National Energy Board (NEB). The Electricity Branch of EMR combined these two sources of forecasts and produced an overall electricity demand forecast for the provinces and territories. As Table 12.1 indicates, electricity demand for Canada as a whole is expected to grow at an average of 1.8 per cent during the period 1991-2010. This projected growth rate was slightly less than last year's forecast of 2.1 per cent for the same period.

Figure 12.1 presents various forecasts for overall electricity demand in Canada. Included for comparison are the latest forecasts derived from EMR's Interfuel Substitution Demand Model, the NEB's Supply and Demand Model, and forecasts provided mainly by the major electric utilities. On the basis of control case, the NEB's projection of electricity demand for the next 19 years is 1.7 per cent annually, compared with the utilities' 1.8 per cent, and EMR's 1.5 per cent. All of these forecasts, however, are significantly lower than the average annual growth rate of 4.8 per cent achieved during the period 1960-91.

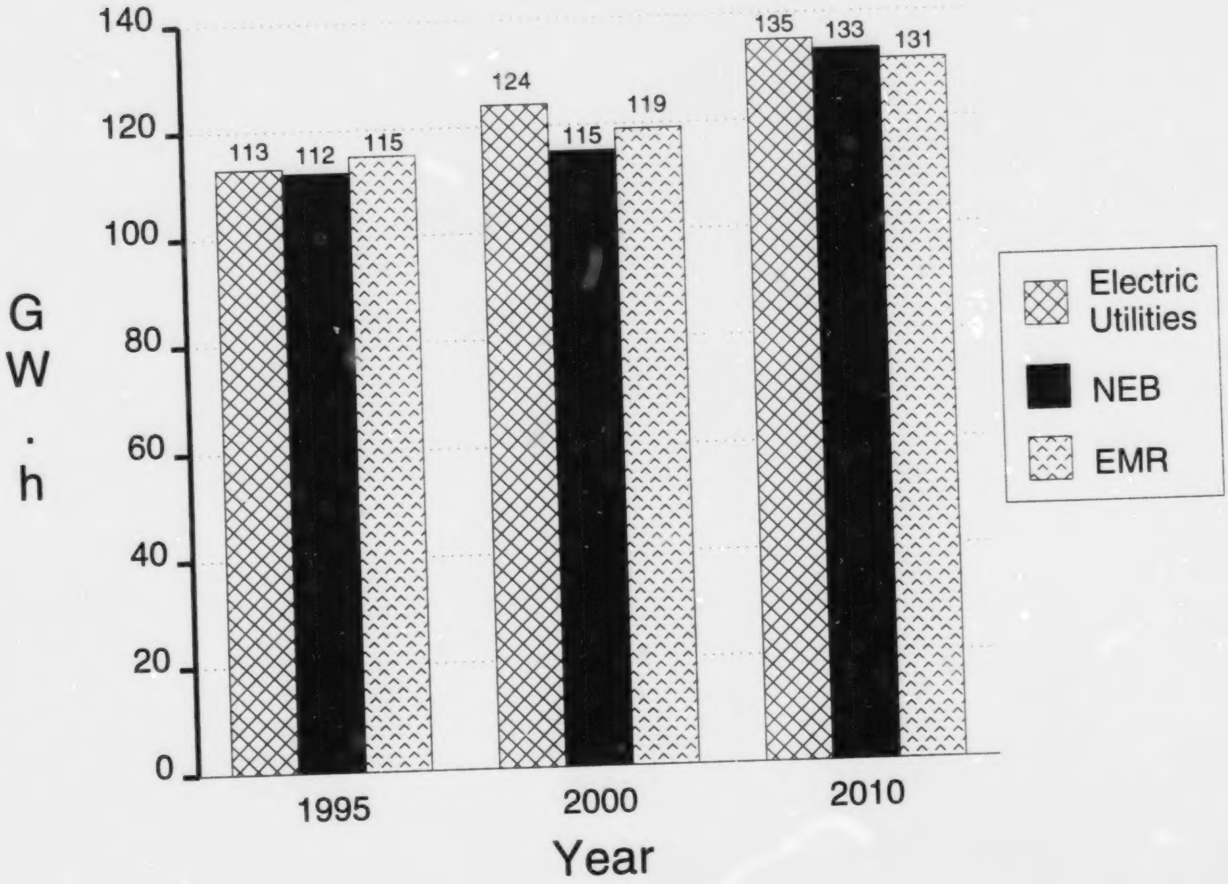
Table 12.2. Forecasts of domestic peak demand

	1991*	1992	1995	2000	2005	2010	Average Annual Growth Rate 1991-2010
				(MW)			(%)
Nfld.	1 852	1 924	2 056	2 288	2 536	2 775	2.2
P.E.I.	137	136	144	159	181	206	2.2
N.S.	1 887	1 982	2 083	2 218	2 391	2 631	1.8
N.B.	2 757	2 941	3 069	3 425	3 742	4 109	2.1
Que.	29 357	30 380	32 497	36 447	38 807	41 487	1.8
Ont.	24 489	25 647	27 466	28 067	28 882	30 804	1.2
Man.	3 809	3 877	4 503	5 366	5 843	6 221	2.6
Sask.	2 371	2 643	2 854	3 067	3 231	3 382	1.9
Alta.	6 515	7 100	7 769	8 766	9 488	10 272	2.4
B.C.	9 492	10 669	11 321	12 396	13 286	14 066	2.1
Yukon	82	88	89	100	112	125	2.2
N.W.T.	115	119	126	128	133	138	1.0
Canada	82 863	87 506	93 977	102 427	108 632	116 216	1.8

** Actual data.*

Source: Canadian electric utilities and National Energy Board.

Figure 12.2. Comparison of generating capacity forecasts



FORECASTS OF PEAK DEMAND

The operation of an electrical system must meet two basic requirements: to generate enough energy to meet energy demand, and to have enough capacity to satisfy peak demand. All major electric utilities in the ten provinces and two territories have their peak loads in winter. Table 12.2 reports winter peaks projected mainly by the major electric utilities for the period 1991-2010. For Canada as a whole, peak demand is expected to grow at an average annual rate of 1.8 per cent, which is the same as that projected for energy demand. This suggests that the load factor for Canada's electrical system will stabilize at about 65 per cent during the period 1991-2010.

FORECASTS OF GENERATING CAPACITY

To meet the forecast growth in electricity demand shown in tables 12.1 and 12.2, total installed generating capacity in Canada is expected to increase from 105 GW at the end of 1991 to about 135 GW by the end of 2010, with an average annual growth rate of 1.3 per cent (Table 12.3). This level of growth is slightly lower than those levels projected for energy and peak demand growth, reflecting the current surplus capacity situation in some of the provinces.

Table 12.4 presents installed generating capacity by fuel type for the period 1991-2010. Because of public concern about the environment, the capacity share of coal-fired generation is expected to decline significantly from about 19 per cent of the total capacity in 1991 to 13 per cent by the year 2010. Oil-fired and natural gas-fired generation are mainly reserved for peaking

Table 12.3. Forecasts of installed generating capacity by province

	1991*	1992	1995	2000	2005	2010	Average Annual Growth Rate 1991-2010
				(MW)			(%)
Nfld.	7 462	7 472	7 480	8 252	8 458	8 458	0.7
P.E.I.	122	124	149	124	178	178	2.0
N.S.	2 306	2 221	2 371	2 991	2 536	2 866	1.2
N.B.	3 543	3 592	4 014	4 630	4 825	5 145	2.0
Que.	29 879	30 628	34 690	38 369	40 931	47 096	2.4
Ont.	32 729	31 915	33 960	35 111	32 650	33 444	0.1
Man.	4 946	4 843	5 227	5 707	6 193	6 088	1.1
Sask.	2 846	2 846	3 090	3 683	3 597	3 776	1.5
Alta.	7 976	8 076	8 710	11 622	10 451	12 316	2.3
B.C.	12 497	12 505	13 015	13 451	13 315	15 047	1.0
Yukon	126	131	132	179	146	154	1.1
N.W.T.	199	184	203	189	214	219	0.5
Canada	104 631	104 537	113 041	124 308	123 494	134 787	1.3

**Actual data.*

Source: Canadian electric utilities and National Energy Board.

Figure 12.3. Comparison of electricity generation forecasts

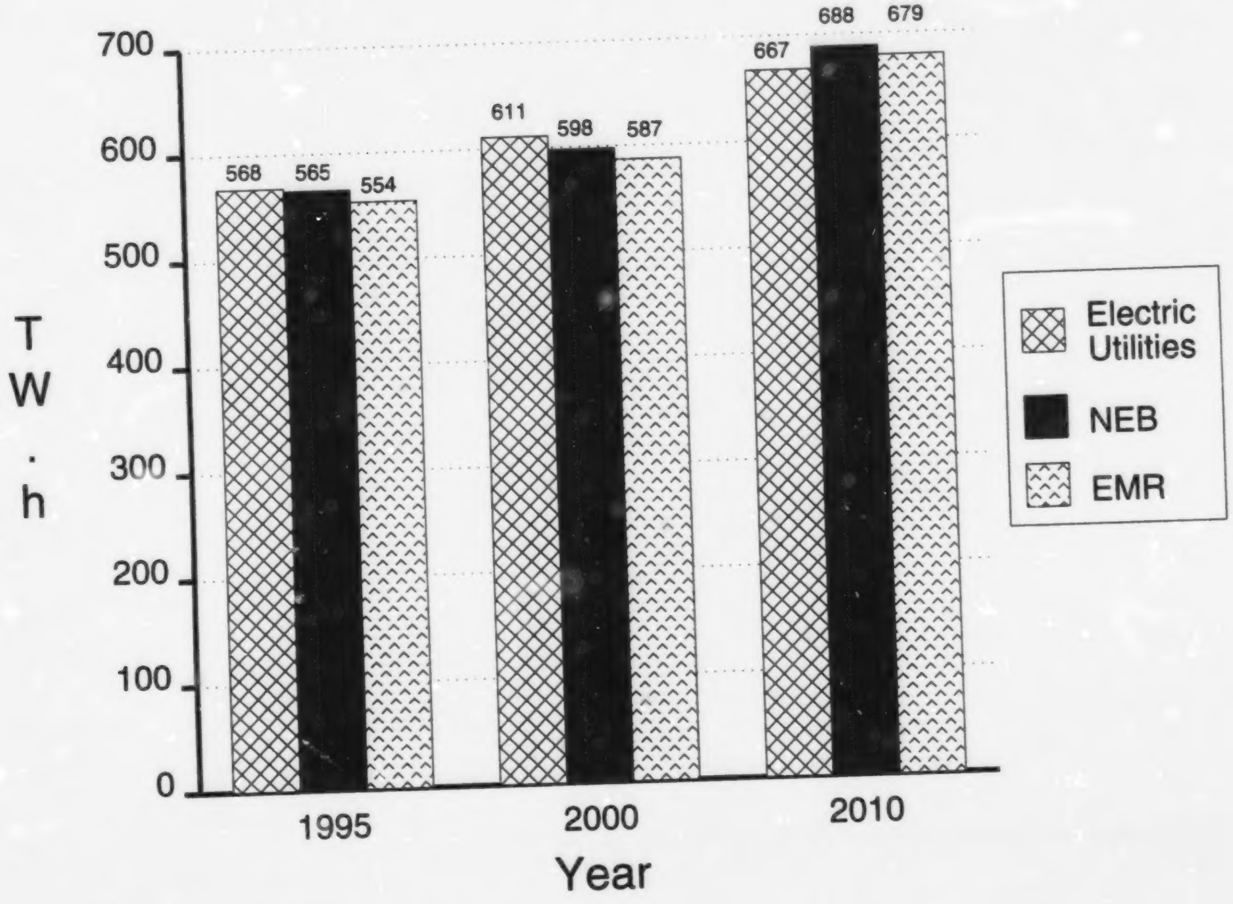


Table 12.4. Forecasts of installed generating capacity by fuel type in Canada

	1991*	1992	1995	2000	2005	2010
			(MW)			
Coal	19 711	18 064	19 440	22 201	18 258	17 343
Oil	7 346	7 355	7 764	8 223	8 363	9 796
Natural gas	3 577	3 502	3 801	5 067	3 854	3 921
Nuclear	13 052	13 767	15 529	15 517	14 760	15 683
Hydro**	60 255	61 069	65 209	72 228	74 289	81 276
Other***	690	780	1 298	1 072	3 970	6 768
Total	104 631	104 537	113 041	124 308	123 494	134 787

* *Actual data.*
** *Includes 20 MW of tidal power.*
*** *Generating capacity from woodchips, waste gases, and non-utility generators.*

Source: Canadian electric utilities and National Energy Board.

Table 12.5. Utility forecasts of electricity generation by province

	1991*	1992	1995	2000	2005	2010	Average Annual Growth Rate 1991-2010
				(GW.h)			(%)
Nfld.	36 968	40 769	41 347	41 829	42 804	43 866	0.9
P.E.I.	71	165	340	450	450	450	10.2
N.S.	9 385	10 055	10 416	11 245	12 280	13 629	2.0
N.B.	15 759	15 496	19 369	20 635	23 648	25 181	2.5
Quebec	142 281	164 900	177 410	194 110	199 900	212 900	2.1
Ontario	140 671	143 718	154 585	164 941	164 955	170 424	1.0
Man.	22 871	28 054	28 950	30 324	35 679	35 081	2.3
Sask.	13 576	14 693	15 970	17 270	18 231	19 138	1.8
Alta.	43 721	46 589	51 259	58 411	63 296	68 590	2.4
B.C.	62 981	60 865	67 385	70 760	71 720	76 300	1.0
Yukon	456	505	533	597	669	749	2.5
N.W.T.	478	527	550	569	586	606	1.3
Canada	489 227	526 336	568 114	611 141	634 218	666 914	1.6

***Actual data.**

Source: Canadian electric utilities and National Energy Board.

purposes, and their capacity shares are expected to stabilize at 7 per cent and 3 per cent of the total respectively over the same forecast period. The capacity shares of hydro is expected to increase at 58 per cent in 1991 to 62 per cent by 2010, while the nuclear share is projected to decrease slightly from 13 per cent of the total in 1991 to 12 per cent by 2010 due to the morotorium of the nuclear program in Ontario. However, other installed capacity, including non-utility generators, is expected to increase substantially; its share in the total installed capacity is expected to increase from 0.7 per cent in 1991 to about 5 per cent by 2010.

Figure 12.2 compares various forecasts of total generating capacity in Canada for the period 1991-2010. Again, the electric utilities' forecasts are on the high side, followed by the NEB and EMR. Between 1991 and 2010, the electric utilities project new capacity additions of 30 GW, or about 1 590 MW per year. The NEB projects capacity additions of 28 GW, or 1 470 MW per year, and EMR projects new additions of 26 GW, or 1 370 MW per year. In terms of the growth rate, the electric utilities' projection is 1.3 per cent annually, compared with 1.25 per cent for the NEB and 1.17 per cent for EMR.

FORECASTS OF ELECTRICITY GENERATION

To meet both domestic electricity demand (Table 12.1) and export requirements (Table 12.7), the electric utilities have forecast total electricity generation for the period 1991-2010 (Table 12.5). It is expected that hydro-based generation will continue to be the most important source of electric energy in Canada, with its share of total electricity production declining by 2 per cent, from 62 per cent in 1991 to 60 per cent in 2010. Coal-fired production is also expected to decrease its market share by 3 per cent, from 17 per cent in 1991 to 14 per cent by 2010, again largely because of environmental concerns.

Even though falling world oil prices in recent years have provided electric utilities with an economic incentive to utilize their existing oil-fired stations in the short term, oil prices are not expected to remain low for a long period of time. In the long term, oil-fired stations will continue to be used mainly as peaking

Table 12.6. Forecasts of electricity generation by fuel type in Canada

	1991*	1992	1995	2000	2005	2010
			(GW.h)			
Coal	82 018	88 998	87 018	87 952	92 018	91 505
Oil	12 349	16 142	14 472	16 595	15 947	17 191
Natural gas	7 804	10 482	14 028	19 083	19 597	15 441
Nuclear	80 123	75 504	97 421	106 859	101 016	107 960
Hydro	304 328	331 967	347 211	368 561	384 384	401 267
Other**	2 605	3 243	7 343	12 091	21 256	33 550
Total	489 227	526 336	568 114	611 141	634 218	666 914

* *Actual data.*
** *Electrical generation from woodchips, waste gases, and non-utility generators.*

Source: Canadian electric utilities and National Energy Board.

Table 12.7. Electricity exports to the United States

	1991*	1992	1995	2000	2005	2010
			(GW.h)			
New Brunswick	3 086	2 880	3 272	2 959	3 579	2 603
Quebec	5 784	11 600	9 200	18 500	12 500	12 500
Ontario	2 314	461	5 500	8 114	7 556	7 946
Manitoba	3 316	8 069	9 167	7 340	4 086	2 962
Saskatchewan	59	116	88	88	88	88
British Columbia	5 269	2 000	3 440	7 440	6 890	6 930
Canada	19 828	25 126	30 667	44 441	34 699	33 029

* *Actual data.*

Source: Canadian electric utilities and National Energy Board.

Table 12.8. Fuels required for electricity generation

	Coal (10^3 tonnes)	Oil (m^3)	Natural Gas ($10^6 m^3$)	Uranium (tonnes)
1991*	45 313	3 161 190	2 239	1 517
1992	48 682	3 950 334	2 887	1 478
1995	48 397	3 808 401	3 908	1 729
2000	47 474	4 377 345	5 041	1 815
2005	47 682	4 247 578	5 225	1 717
2010	47 269	4 608 430	4 065	1 834

* *Actual data.*

Note: 1 m^3 oil = 6.3 bbls
1 m^3 gas = 35.5 ft^3
1 tonne = 1000 kg

Source: Canadian electric utilities and National Energy Board.

capacity and to meet energy demand in remote locations. Beyond 1991, the use of oil in electricity generation is expected to stabilize with the overall increase in demand. By the year 2010, the share of electricity generated from oil is expected to be 2.6 per cent of total electricity generation, compared with 2.5 per cent in 1991.

In the long term, the use of natural gas for electricity generation is expected to stabilize around 2 per cent of the total generation.

The nuclear share of electricity generation is also expected to stabilize at 16 per cent during the period 1991-2010. New nuclear capacity will come from the Darlington station in Ontario, which is expected to be completed by 1993. With no other nuclear stations under construction, the nuclear share of electricity generation is expected to decline after the year 2010.

It is worth noting that electric utilities, especially Ontario Hydro, TransAlta Utilities and B.C. Hydro, have projected a considerable amount of electricity to be derived from non-utility generation. Table 12.6 indicates that electricity generation from other sources, which includes non-utility generation, is expected to increase substantially starting in 1995. By the end of 2010, non-utility generation is expected to account for about 5 per cent of total electricity generation, compared with only 0.5 per cent in 1991.

A comparison of various forecasts of electricity generation is presented in Figure 12.3. Between 1991 and 2010, NEB projects that electricity generation will grow at average annual rate of 1.8 per cent. EMR projects an annual growth rate of 1.7 per cent, and the electric utilities an annual growth rate of 1.6 per cent.

FORECASTS OF ELECTRICITY EXPORTS TO THE UNITED STATES

Canada and the United States enjoy essentially free trade in electricity: there is little direct

Table 12.9. Total capital expenditures for major electric utilities

	1991*	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
					(millions of current dollars)						
Nfld.	91	106	150	219	244	482	688	950	1 108	1 131	840
P.E.I.	17	14	15	87	48	16	9	11	11	11	11
N.S.	379	280	140	114	111	94	111	115	148	288	427
N.B.	600	579	402	203	113	113	215	328	204	239	278
Que.	4 074	4 633	5 453	5 260	5 216	5 660	6 026	6 461	5 741	4 712	4 697
Ont.	4 200	4 200	3 500	3 500	3 700	4 600	5 100	4 900	5 100	4 600	4 600
Man.	47	392	488	459	575	591	962	1 167	1 475	235	808
Sask.	365	284	304	317	380	291	205	167	221	366	449
Alta.	695	683	630	609	599	511	529	539	545	568	589
B.C.	144	243	339	295	373	374	388	307	307	326	324
Yukon	11	14	34	15	7	10	9	9	10	11	12
N.W.T.	19	33	24	23	27	24	24	24	24	24	24
Canada	10 642	11 461	11 479	11 101	11 393	12 766	14 266	14 978	14 894	12 511	13 059

** Actual data.*

Source: Canadian electric utilities, and Energy, Mines and Resources Canada.

government involvement in the contracting process, there are no tariffs, and there is a minimum of regulation. With the Canada-United States Free Trade Agreement now in place, other non-trade barriers will be eliminated, gradually permitting an increase of electricity trade between the two countries. Table 12.7 reports electric utilities' projected electricity exports to the United States for the period 1991-2010.

FORECASTS OF FUEL REQUIREMENTS

Forecast fuel requirements are reported in Table 12.8; they are based on the forecasts of energy generation given in Table 12.6. Between 1991 and 2010, coal consumption in Ontario is expected to decline by 4.8 million tonnes because of the increase in nuclear generation. Nevertheless, in Nova Scotia, the use of coal is expected to increase by 2 million tonnes, and in New Brunswick by 1.5 million tonnes. The traditional coal-consuming provinces, Saskatchewan and Alberta, are estimated to increase their coal consumption for electricity generation by 3 and 6 million tonnes.

The use of oil for electricity generation is forecast to increase slightly. As noted earlier, the use of oil will be restricted to meeting peak demand and providing electricity to remote communities.

Over the forecast period, 1991 to 2010, the use of natural gas for electricity generation is projected to increase at 3 per cent per year. Major industrial establishments, mainly in Alberta and Ontario, are the largest users. The major electric utilities in Alberta and British Columbia also use a substantial amount of natural gas for electricity generation.

With nuclear energy now an important component of Canada's electricity supply, the use of uranium for electricity generation is expected to increase at about 1 per cent per year.

Table 12.10. Capital expenditures for major electric utilities (Generation)

	1991*	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
	(millions of current dollars)										
Nfld.	28	31	72	134	175	361	378	528	618	560	413
P.E.I.	6	6	5	80	38	8	1	1	1	1	1
N.S.	254	150	43	10	7	7	7	8	35	107	278
N.B.	470	451	302	105	27	21	120	229	101	132	165
Que.	2 046	2 195	2 522	2 420	2 535	2 776	3 027	2 861	2 319	1 646	1 935
Ont.	2 400	2 100	1 500	1 300	1 300	1 500	1 700	1 500	1 400	1 200	1 400
Man.	21	184	237	217	332	439	546	651	625	50	480
Sask.	172	142	133	164	164	86	48	21	76	212	274
Alta.	262	256	323	283	174	157	157	149	152	156	162
B.C.	25	39	63	50	55	94	141	89	59	60	66
Yukon	7	6	8	9	3	7	7	7	8	8	9
N.W.T.	15	28	20	19	22	20	20	20	20	20	20
Canada	5 706	5 588	5 228	4 791	4 832	5 476	6 152	6 064	5 414	4 152	5 203

** Actual data.*

Source: Canadian electric utilities and Energy, Mines and Resources Canada.

Table 12.11. Capital expenditures for major electric utilities (Transmission)

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
	(millions of current dollars)										
Nfld.	14	18	13	24	14	27	189	264	310	298	218
P.E.I.	2	0	0	0	3	0	1	1	1	1	1
N.S.	58	61	21	27	24	9	22	23	25	90	55
N.B.	67	70	32	26	14	17	17	18	19	19	20
Que.	971	866	1 227	973	746	661	657	1 155	1 273	800	466
Ont.	900	1 100	900	1 000	1 200	1 800	1 800	1 700	1 900	1 400	1 400
Man.	19	122	147	129	115	54	313	407	724	58	205
Sask.	88	28	33	19	73	64	9	15	15	5	43
Alta.	154	193	100	101	180	111	127	138	134	136	139
B.C.	19	44	77	62	81	95	97	109	139	137	178
Yukon	2	6	25	4	2	1	1	1	1	1	1
N.W.T.	1	0	1	1	1	1	1	1	1	1	1
Canada	2 295	2 508	2 576	2 366	2 453	2 840	3 234	3 832	4 542	2 946	2 727

** Actual data.*

Sources: Canadian electric utilities and Energy, Mines and Resources Canada.

Table 12.12. Capital expenditures for major electric utilities (Distribution)

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
	(millions of current dollars)										
Nfld.	34	39	43	43	41	62	89	106	120	184	142
P.E.I.	7	5	6	4	4	4	4	5	5	5	5
N.S.	43	58	63	64	66	66	68	70	73	76	78
N.B.	43	44	54	57	56	59	61	63	66	69	73
Que.	565	896	990	1 074	1 127	1 179	1 277	1 314	1 180	1 286	1 330
Ont.	200	200	200	300	300	300	500	500	500	600	600
Man.	2	44	54	56	54	50	51	52	56	59	62
Sask.	95	103	126	121	133	130	137	122	120	138	122
Alta.	192	151	142	159	166	175	178	184	189	204	215
B.C.	75	115	171	151	190	145	118	82	82	100	50
Yukon	1	1	1	1	1	1	1	1	1	1	2
N.W.T.	1	2	1	1	1	1	1	1	1	1	1
Canada	1 258	1 658	1 851	2 031	2 139	2 172	2 485	2 500	2 393	2 723	2 680

** Actual data.*

Sources: Canadian electric utilities and Energy, Mines and Resources Canada.

FORECASTS OF CAPITAL EXPENDITURES

Over the next ten years 1992-2001, major electric utilities in Canada are expected to invest about $128 billion in facilities, an average of $13 billion per year. Quebec will be the largest investor, with $54 billion, accounting for 42 per cent of the total. A large share of this capital investment will be spent on the James Bay Phase II and Grande Baleine hydro projects. Ontario is expected to invest about $44 billion in electrical energy, or about 34 per cent of Canada's total. Most of this expenditure will be for the completion of Darlington and some hydro projects (Table 12.9).

The electric utilities' capital investments by function are given in Tables 12.10 - 12.13. It is expected that generating facilities will account for 41 per cent of the total for the period 1992-2001, transmission 24 per cent, distribution 18 per cent, and other facilities 17 per cent.

FORECAST OF EMISSIONS FROM ELECTRICITY GENERATION

Electric utilities project that the carbon dioxide emissions will continue to increase during the next 19 years; from 93 million tonnes in 1991 to about 105 million tonnes by 2010 (Figure 12.4). Coal-fired generation is expected to account for 86 per cent of the total, followed by 11 per cent for oil, and 3 per cent for natural gas.

Because of the application of new technologies to reduce emissions, electric utilities project that their sulphur dioxide emissions will be reduced significantly over the period 1991-2010 (Table 12.14). The projections of nitrous oxides emissions are shown in Table 12.15.

Table 12.13. Capital expenditures for major electric utilities (Other)

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
					(millions of current dollars)						
Nfld.	15	18	22	18	14	32	32	52	60	89	67
P.E.I.	2	3	4	3	3	4	3	4	4	4	4
N.S.	24	11	13	13	14	12	14	14	15	15	16
N.B.	20	14	14	15	16	16	17	18	18	19	20
Que.	492	676	714	793	808	1 044	1 065	1 131	969	980	966
Ont.	700	800	900	900	900	1 000	1 100	1 200	1 300	1 400	1 200
Man.	5	42	50	57	74	48	52	57	70	68	61
Sask.	10	11	12	13	10	11	11	9	10	11	10
Alta.	87	83	65	66	79	68	67	68	70	72	73
B.C.	25	45	28	32	47	40	32	27	27	29	30
Yukon	1	1	0	1	1	1	0	0	0	1	0
N.W.T.	2	3	2	2	3	2	2	2	2	2	2
Canada	1 383	1 707	1 824	1 913	1 969	2 278	2 395	2 582	2 545	2 690	2 449

** Actual data.*

Sources: Canadian electric utilities and Energy, Mines and Resources Canada.

Table 12.14. Forecasts of SO_2 emissions by fuel type in Canada

	Coal	Oil
	(1000 tonnes)	
1991	549	125
1995	483	130
2000	420	148
2005	367	121
2010	352	112

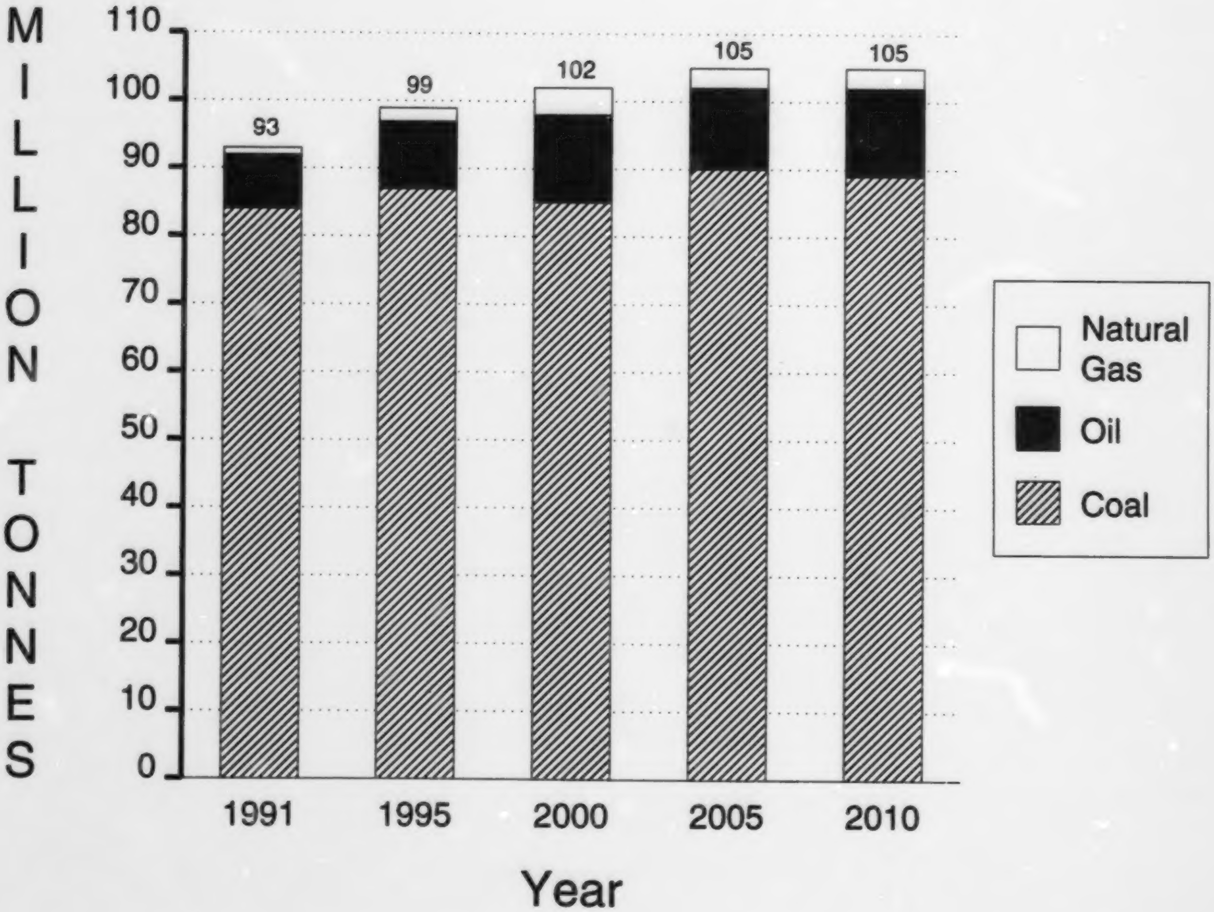
Source: Canadian electric utilities

Table 12.15. Forecasts of NO_x emissions by fuel type in Canada

	Coal	Oil	Natural Gas
		(1000 tonnes)	
1991	193	32	3
1995	195	44	3
2000	174	50	5
2005	161	48	4
2010	156	53	4

Source: Canadian electric utilities

Figure 12.4. Forecasts of CO2 emissions by fuel type



13. DEMAND-SIDE MANAGEMENT

IMPORTANCE OF DEMAND-SIDE MANAGEMENT

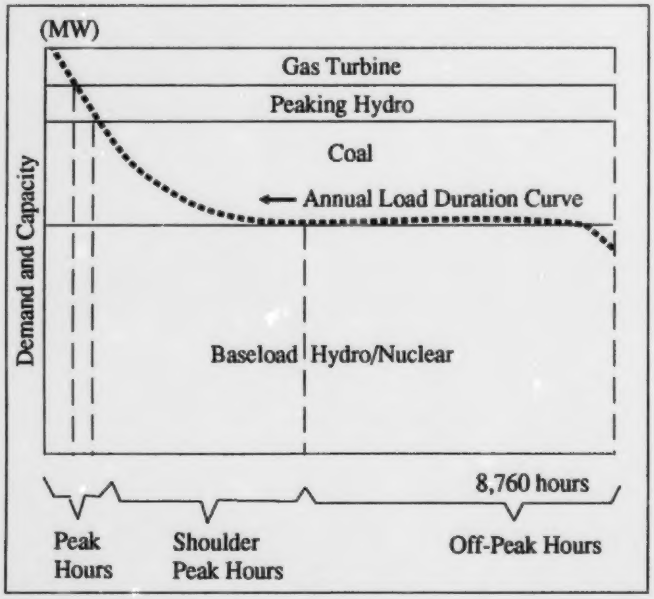
Managing electrical demand is not a new concept for Canadian electric utilities. Utilities have been offering lower rates for interruptible service for many decades, and utility research into improving the efficiency of lighting dates back to the beginning of the century. Entering the 1990s, however, the utilities are increasing their efforts in demand-side management (DSM), and in some provinces individual initiatives are being integrated into comprehensive demand-management programs. Canadian utilities see these programs as a means of providing quality electrical service in a flexible, economic and environmentally sensitive manner.

The traditional role of the electric utility has been to respond to increases in the demand for electrical energy by building new generating capacity. This approach has led to undirected growth that is served at whatever scale and whatever time of day or year it is required.

Operations designed to meet rather than manage load have cost implications for the utility and eventually the utility's customers. Under traditional utility planning practice, increases in load resulted in a need to bring additional generating resources on-line. Over time, utilities are forced to develop increasingly more expensive generating resources, e.g. isolated hydroelectric projects, new or different fuel sources, and imports. New developments become increasingly more expensive and in some cases are associated with large environmental costs.

To serve this uncontrolled load growth, utilities have also had to adapt their operations to customer-use patterns. To do this while keeping generation costs low, utilities have had to optimize the use of their supply. Two considerations are important in this optimization: (i) the fixed and variable costs of various forms of production, and (ii) the costs of changing electrical

Figure 13.1. Typical annual load duration curve and generation cost minimization for an electric utility



output levels over a short period of time. As a result of these cost considerations, the most economic means of serving load, generally, has been for utilities to maximize the use of generation with (i) low variable cost sources (hydro and nuclear facilities) to serve baseload requirements and (ii) higher variable cost sources (coal, gas and pumped storage) to serve intermediate- and peak-load requirements. Figure 13.1 illustrates the resources that a typical utility might use to meet its annual load.

As Canadian utilities evaluate the means of providing electrical service to meet future demand, increasingly they are recognizing the growing mismatch between the rising costs of generation and the cost of DSM options. DSM refers to the various actions that can be taken to reduce the costs of providing electrical service through changes in the pattern and magnitude of electricity use.

OBJECTIVES OF DSM

Utilities generally pursue DSM in order to (i) maximize efficiency in their existing operations (i.e. reduce the use of costlier fuels and the period that generating plants sit idle); and (ii) minimize the requirement for new plants (i.e. reduce the need for peaking capacity, and delay the need for baseload capacity additions). The achievement of these goals brings a number of economic and environmental benefits, particularly low electricity rates and reduced environmental impacts.

There are five key objectives of DSM. These are:

Load Reduction -- reducing the amount of electricity required by customers. This can be achieved by improving electrical end-use efficiency.

Load Shifting -- reducing peak electricity demand by moving it to periods of lighter demand. An example of this type of initiative is time-of-use rates that reflect the higher cost of providing electricity during periods of peak demand.

Peak Clipping -- reducing peak electricity demand without shifting it to another period. This can be achieved by offering preferential rates to consumers willing to have load interrupted during peak periods.

Valley Filling -- promoting electricity use during off-peak hours to increase baseload generation and the efficiencies related to it. This can be achieved through reduced rates.

Load Building -- promoting electricity consumption during both the peak and the off-peak periods. Load building can be done through incentives to attract large electricity consumers.

These classifications and examples of typical programs designed to achieve DSM objectives are illustrated in Figure 13.2.

A utility decides which aspects of DSM it will implement based on its balance of demand and supply. Utilities that find themselves with significant excess supply because of a major loss of load, a recent large capacity addition, or lower than anticipated load growth, will tend to emphasize load-building programs. Conversely, as utilities approach a load/resource balance, they will likely emphasize load reduction or shifting efforts.

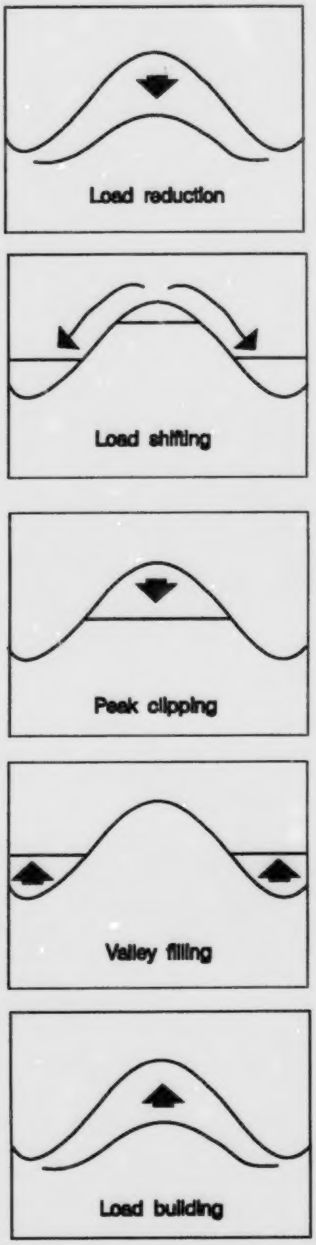
During the early and mid-1980s, many Canadian utilities had surplus generating capacity resulting from lower than anticipated demand. At that time, some utilities introduced programs to build load. These initiatives included advertising campaigns to increase consumption, preferential rates designed to attract energy-intensive industries, programs to promote fuel switching to electricity, and increased electricity export marketing efforts.

Today, the focus has changed. As average Canadian net surplus capacity has declined from 14 per cent in 1980 to 5 per cent in 1991, utilities have cut programs to build load and begun to aggressively pursue load-reduction and load-shifting initiatives individually or in the context of a comprehensive DSM program. Generally these programs involve one or more of alternative pricing policies, direct incentives, direct customer contact, and advertising.

DSM INITIATIVES

For ease of description, the types of initiatives utilities have embarked upon can be grouped into three classifications.

Figure 13.2. Demand-side management objectives and programs


Load reduction
Load shifting
Peak clipping
Valley filling
Load building

- improvements to end-use efficiency
- rate increases and restructuring

- time-of-use rates
- off-peak rates
- thermal energy storage
- direct load control

- time-of-use rates
- interruptible rates
- direct load control

- time-of-use rates
- seasonal rates
- off-peak rates
- thermal energy storage

- promotional rates
- industrial electrotechnologies
- dual-fuel heating
- export marketing

Energy efficiency improvements include utility initiatives designed to increase the efficiency of electricity use among the utility's customers and thereby reduce load. These types of initiatives are generally intended to either improve the penetration of energy-efficient equipment in the marketplace or improve customers' operation of electrical equipment.

Energy efficiency improvements are the main focus of electrical utility DSM initiatives and programs. There are many examples of these types of initiatives. Table E1 of Appendix E lists some programs that Canadian utilities have begun or plan to implement.

Load shifting refers to efforts by the utility to alter the timing of electrical demand among its customers. The goal of load shifting is to reduce peak demand that occurs in the daylight hours and, in Canada, during the winter. Demand is shifted to non-peak periods but total energy demand is not reduced.

Load shifting is more popular among utilities (i) where capacity is constrained, i.e. thermal as opposed to hydraulic systems, and (ii) where meeting the peak requires the operation of more expensive generating units or units with greater environmental impacts. Load shifting is generally done through rate design or direct control. Table E2 of Appendix E describes current Canadian utility initiatives in the area of load shifting.

Interruptible load is the third type of DSM load reduction. It is also possibly the DSM initiative with which utilities have had the most experience. Interruptible load contracts are generally offered to large electricity consumers that have some form of back-up generation. Usually these are industrial or large institutional customers. In an interruptible load contract, the customer receives a preferential electricity rate in return for accepting the risk that electrical service will be curtailed intentionally by the utility in periods of high demand and tight supply.

Table 13.1. Generating capacity savings from electric utilities' DSM cumulative values

	1991 Actual	1992				2000				2010			
		EEI*	LS*	CIL*	Total	EEI	LS	CIL	Total	EEI	LS	CIL	Total
							(MW)						
Nfld.	1	3	0	0	3	0	0	108	108	0	0	0	0
P.E.I.	19	3	0	18	21	7	0	20	27	26	0	21	47
N.S.	0	11	0	170	181	175	0	201	376	293	0	253	546
N.B.	52	25	0	68	93	156	0	80	236	276	0	80	356
Que.	2 436	270	1 680	1 000	2 950	2 070	1 770	1 200	5 040	2 780	1 440	1 200	5 420
Ont.	508	550	221	0	771	3 500	750	0	4 250	6 730	1 193	0	7 923
Man.	0	3	0	0	3	174	19	30	223	313	0	0	313
Sask.	0	294	4	148	446	430	21	191	642	488	21	191	700
Alta.	438	0	13	425	438	180	100	500	780	180	100	500	780
B.C.	75	150	0	0	150	883	0	0	883	1 205	0	0	1 205
Yukon	0	0	0	0	0	0	0	0	0	0	0	0	0
N.W.T.	0	0	0	0	0	0	0	0	0	0	0	0	0
Canada	3 529	1 309	1 918	1 829	5 056	7 575	2 660	2 330	12 565	12 291	2 754	2 245	17 290

*Note: EEI - Electrical efficiency improvements.
LS - Load shifting.
CIL - Capacity interruptible load.

Source: Obtained from a survey undertaken by the Electricity Branch, Energy, Mines and Resources Canada, January 1992.

DSM AND CANADIAN ELECTRIC UTILITIES

Table 13.1 summarizes Canadian utilities' forecasts of generating-capacity savings resulting from the implementation of DSM initiatives and programs for the years 1992, 2000 and 2010. The forecast savings are in excess of any natural capacity savings resulting from more efficient electrical use. The capacity savings are cumulative.

Prior to 1991, electric utilities saved 3529 MW of generating capacity through DSM programs, which accounted for more than 3 per cent of the total generating capacity. Hydro-Québec had the highest savings of 2436 MW, followed by Ontario Hydro with 508 MW, and TransAlta Utilities with 438 MW.

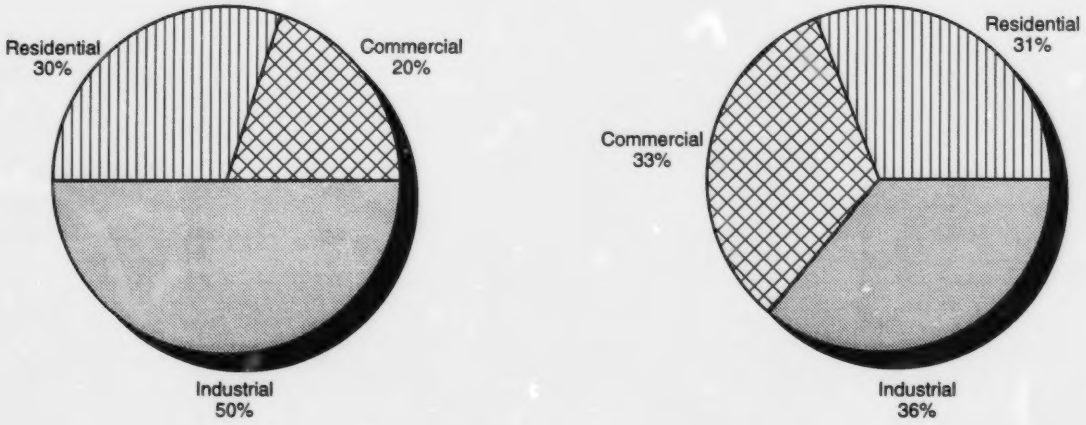
By the end of 1992, Canadian electrical utilities forecast DSM generating-capacity savings of about 5056 MW. The demand-side savings apply mainly to peak demand reductions, either through peak clipping or peak shifting.

The majority of the projected DSM savings will result from load-shifting initiatives, particularly as a result of Hydro-Québec's dual-energy program. Under this program, residential, commercial and industrial consumers use electricity for heating most of the time but switch to another source of energy, such as heating oil, during peak heating periods (defined as when the temperature drops below a certain benchmark). In exchange for switching off electricity during these peak periods, customers on this program receive a reduced rate for their off-peak consumption.

Interruptible load will also contribute significantly to generating-capacity savings. This reflects mainly historic contracts with large consumers that are willing to accept occasional interruptions in service in exchange for reduced electrical rates. Most utilities offer such interruptible contracts. Hydro-Québec predicts 1000 MW of capacity interruptible load in 1992.

Only 3 per cent of 1990 Canadian utility capacity savings from DSM

Figure 13.3. Generating capacity savings by sector due to DSM*



1992

2000

** Based on utility responses identifying capacity savings by sector, i.e. total savings in 1992 of 5056 MW and in 2000 of 12 394 MW.*

came from energy-efficiency improvements. The number was about 19 per cent in 1991. However, this percentage is expected to increase to 25 per cent in 1992, reflecting the time lag of program development, implementation and penetration.

By the year 2000, the total DSM savings are expected to climb to 12 565 MW. At that time, about 60 per cent of the DSM savings will result from energy-efficiency improvements. These initiatives will be the basis of DSM programs for B.C. Hydro, SaskPower, Manitoba Hydro, Ontario Hydro, Hydro-Québec, and New Brunswick Power. Utilities in Newfoundland, Prince Edward Island, Nova Scotia, and Alberta will continue to rely on capacity interruptible load for the bulk of their DSM savings.

Electrical efficiency improvements will continue to be the major source of generating capacity savings to the year 2010. By that time, total savings are expected to climb to 17 290 MW. Of this total, 12 291 MW (or 71 per cent) is attributed to electrical efficiency improvements.

Figure 13.3 illustrates the sectors from which the forecast savings will come. The information shows that, in 1992, 50 per cent of the savings will come from the industrial sector, reflecting the emphasis utilities have placed on load shifting and interruptible contracts with their large industrial customers. By 2000, the distribution of savings will be more balanced among the residential, commercial, and industrial sectors. This reflects the anticipated success of energy-efficiency improvements in the commercial sector, particularly improvements in lighting efficiency. Industrial savings are expected to account for 36 per cent of total peak-load savings by the year 2000.

Table 13.2 summarizes energy savings resulting from electrical efficiency improvements. It is estimated that about 4966 GW.h of electricity will be saved in 1992, compared with only 581 GW.h in 1990, and 1930 GW.h in 1991. The real impact of initiatives in this area will be significant by the year 2000, approaching 30 845 GW.h. The energy-savings are expected to increase to over 47 000 GW.h by 2010.

Table 13.2. Energy savings from electric utilities' efficiency improvements

	1991 Actual	1992	2000	2010
		(GW.h)		
Nfld.	6	14	14	14
P.E.I.	2	8	145	145
N.S.	0	45	711	1 188
N.B.	14	75	689	1 268
Quebec	226	741	10 289	14 226
Ontario	1 257	2 320	11 345	20 255
Manitoba	-	15	810	1 414
Sask.	-	672	1 182	1 505
Alberta	-	250	900	900
B.C.	425	826	4 760	6 515
Canada	1 930	4 966	30 845	47 430

Source: Obtained from a survey undertaken by the Electricity Branch, Energy, Mines and Resources Canada, January 1992

PROJECTED CAPITAL COSTS OF DSM

Most utilities are unable to estimate the costs of the DSM programs and initiatives that they are planning to undertake. Part of the reason relates to difficulties in determining the penetration rate of such programs. Another reason is that load reduction programs account for much of the DSM effort, and establishing the costs of these programs is complex and in many instances dependent upon the frequency of unanticipated shortages. Some of the smaller utilities identified that their DSM planning is not as detailed nor as long-term as other resource planning.

The three largest Canadian electrical utilities (Hydro-Québec, Ontario Hydro and B.C. Hydro) have all implemented aggressive DSM programs and have been able to forecast the cost of these programs. Cumulatively, their efforts in DSM are expected to account for 94 per cent of total Canadian utility savings over the period 1992-2010. Their DSM expenditures to the year 2000 are forecast to be $8 billion ($ current). Ontario Hydro's expenditures on DSM will account for $4.5 billion, Hydro-Québec for $3 billion, and B.C. Hydro will account for the remainder. In 1992, electric utilities across Canada spent about $375 million on DSM programs.

14. NON-UTILITY GENERATION

Non-Utility Generation (NUG) is defined here as electrical generation owned and operated in each province and territory by electricity producers other than the major electric utilities reported in Table 1.1. Historically, non- utility generation included minor utility and industry generation. In this chapter, non-utility generation, independent power production and parallel generation are used synonymously. This chapter examines the power purchase policies of the major utilities and the potential for NUG in Canada.

CURRENT NUG STATUS

As of December 31, 1991, the total installed NUG capacity in service in Canada was estimated to be about 7477 MW, or about 7.2 per cent of Canada's total capacity. Of this total, 6155 MW (82 per cent) was owned and operated by industrial establishments, mainly pulp and paper, mining and aluminum smelting (Table 14.1). The remaining 1322 MW (18 per cent) was generated by the minor utilities, including small private utilities and municipal utilities (Table 14.2).

The majority of total installed NUG capacity is hydro, about 5597 MW (75 per cent of the total). It is followed by natural gas with 923 MW (12 per cent), other (wood waste, flare gas, etc.) with 687 MW (9 per cent), and oil with 270 MW (4 per cent). About 45 per cent of NUG capacity is located in Quebec, 27 per cent in British Columbia, 16 per cent in Ontario, and 6 per cent in Alberta.

It is estimated that a total of 47 986 GW.h of electricity was generated by NUG facilities in 1991, accounting for 9.8 per cent of total generated electricity in Canada. Of this total, 40 383 GW.h (84 per cent) was industrial generation, and the remainder was generated by the minor utilities (Tables 14.3 and 14.4). About 38 526 GW.h (80 per cent) of this energy was hydro generated, followed by natural gas with 5335 GW.h (11 per cent), other generation with 2734 GW.h (6 per cent), and oil with 1383 GW.h (3 per cent).

Table 14.1. Industrial installed generating capacity by fuel type, 1991

	Conventional Thermal							
	Coal	Oil	Gas	Sub-total	Nuclear	Hydro	Other	Total
				(MW)				
Nfld.	0	20	0	20	0	85	5	110
P.E.I.	0	0	0	0	0	0	0	0
N.S.	0	29	0	29	0	5	19	53
N.B.	0	77	0	77	0	17	87	181
Quebec	0	22	8	30	0	2 573	5	2 608
Ontario	0	0	437	437	0	296	91	824
Manitoba	0	3	4	7	0	0	23	30
Sask.	0	21	38	59	0	0	22	81
Alberta	0	1	357	358	0	0	65	423
B.C.	0	94	51	145	0	1 305	370	1 820
Yukon	0	0	0	0	0	0	0	0
N.W.T.	0	2	20	22	0	3	0	25
Canada	0	269	915	1 184	0	4 284	687	6 155

Source: Electric Power Statistics, Volume III, Statistics Canada, catalogue 57-206 and Electricity Branch, Energy, Mines and Resources Canada.

POWER PURCHASE POLICIES

The electricity generated by non-utility generators may be purchased either outright by the major electric utilities or used to meet the producers' own electricity needs. Although non-utility generators produced 47 986 GW.h of electricity in 1991, it is estimated that less than 4400 GW.h (9.2 per cent) of this was sold to the major utilities. B.C Hydro purchased about 3300 GW.h, followed by Hydro-Québec (519 GW.h), and Ontario Hydro (500 GW.h). The remaining 1991 NUG was for independent use.

Most major electric utilities now support NUG projects. In general, the goal is to promote and establish maximum economic NUG for the benefit of the province. To this end, a number of major utilities have modified or announced power purchase policies, and the majority will purchase electricity from non-utility generators at rates that reflect their long-term value to the power system.

Most major utilites have fixed-rate power purchase policies in place with the exception of utilities in Newfoundland and Saskatchewan. Table E3 of Appendix E summarizes power purchase rates for non-utility generators selling to major utilities across Canada.

Following, is an outline of NUG policies now in place in some of the provinces.

Ontario Hydro's current policy on NUG in Ontario includes the following:

- To promote and establish the development of maximum economic NUG for the benefit of Ontario;
- To purchase electricity from non-utility generators at rates that reflect the long-term value of this resource to Ontario Hydro's system as a whole;
- To purchase generation from non-utility generators with power ratings of 5 MW or less through standard preapproved rate schedules; and
- To purchase generation from non-utility generators with

Table 14.2. Minor utility installed generating capacity by fuel type, 1991

	Conventional Thermal							
	Coal	Oil	Gas	Sub-total	Nuclear	Hydro	Other	Total
					(MW)			
Nfld.	0	0	0	0	0	134	0	134
P.E.I.	0	0	0	0	0	0	0	0
N.S.	0	0	0	0	0	0	0	0
N.B.	0	1	0	1	0	36	0	37
Quebec	0	0	0	0	0	605	0	605
Ontario	0	0	8	8	0	336	0	344
Manitoba	0	0	0	0	0	0	0	0
Sask.	0	0	0	0	0	0	0	0
Alberta	0	0	0	0	0	0	0	0
B.C.	0	0	0	0	0	202	0	202
Yukon	0	0	0	0	0	0	0	0
N.W.T.	0	0	0	0	0	0	0	0
Canada	0	1	8	9	0	1 313	0	1 322

Source: Electric Power Branch, National Energy Board, March 1992 and Electricity Branch, Energy Mines and Resources Canada, March 1992.

power ratings greater than 5 MW through negotiations or by requests for proposals.

In Alberta, the provincial government passed the Small Power Research and Development Act on May 11, 1988. The purpose of the Act is to facilitate the generation of electricity in Alberta through small projects using renewable wind, hydro and biomass resources, and to monitor production from small power projects. The results of the monitoring will allow Alberta to determine the contribution that small power can make in the long term.

Under the Act, the purchase price of the power will be fixed at 5.2 cents per kW.h until 1994, and the amount of power purchased at this price will be limited to 125 MW. Contracts will be limited to between 15 and 25 years.

In June 1988, B.C. Hydro issued a new private power purchase policy. The policy is a major component of B.C. Hydro's 20-year resource plan. Purchases will be made from independent power production in any of the following categories:

- Directly from independent producers;
- Surplus electricity from self-generation, including co-generation;
- Load displacement by self-generation, including co-generation; and
- Load displacement from energy efficiency measures.

Under this policy, B.C. Hydro establishes a fixed purchase price annually for small projects (under 5 MW) to minimize transaction costs. The purchase price reflects a value between B.C. Hydro's short- and long-term marginal costs.

Although Hydro-Québec has purchased industry generation for some time now, Hydromega Development is the first independent power producer in Quebec to develop and operate small hydro generating stations expressly to sell all of its generated energy to Hydro-Québec. Hydromega owns and operates two hydro generating stations with installed capacities

Table 14.3. Industrial energy generation by fuel type, 1991

	Conventional Thermal							
	Coal	Oil	Gas	Sub-total	Nuclear	Hydro	Other	Total
				(GW.h)				
Nfld.	0	0	0	0	0	495	0	495
P.E.I.	0	0	0	0	0	0	0	0
N.S.	0	193	0	193	0	41	143	377
N.B.	0	463	0	463	0	67	261	791
Quebec	0	0	0	0	0	17 524	0	17 524
Ontario	0	211	1 876	2 087	0	1 645	380	4 112
Manitoba	0	20	13	33	0	0	30	63
Sask.	0	10	227	237	0	0	176	413
Alberta	0	0	2 704	2 704	0	0	663	3 367
B.C.	0	485	515	1 000	0	11 135	1 081	13 216
Yukon	0	0	0	0	0	0	0	0
N.W.T.	0	1	0	1	0	24	0	25
Canada	0	1 383	5 335	6 718	0	30 931	2 734	40 383

Source: Electric Power Statistics, Volume III, Statistics Canada, catalogue 57-206 and Electricity Branch, Energy, Mines and Resources Canada.

of 2.4 MW and 2.0 MW. Hydro-Québec purchases Hydromega's full output, and the rates are based on Hydro-Québec's marginal costs. The term of the contract is 20 years.

Another independent power producer in Quebec, located on the North Shore, is currently negotiating with Hydro-Québec for the purchase of the total output of a 20 MW hydroelectric generating complex. The stations would be constructed on the Brador River.

Hydro-Québec estimates that between 1990 and 1995, it will connect 390 MW of independent power production to its system. Of this total, 300 MW will be from co-generation and 90 MW will be from incinerators and small hydro projects.

In Saskatchewan, there are no NUGs operating under contract. The province has 63 MW of installed cogeneration capacity ranging from 26 MW at the Weyerhaeuser pulp mill near Prince Albert, to a small unit at the North Battleford Hospital. These facilities are meeting their own loads and do not supply any excess energy to SaskPower. However, SaskPower has signed a contract with a potential non-utility generator for 15 MW. The proposed Jans Bay peat-fired power plant is expected to be in-service in July 1994.

In November 1990, an Electrical Energy Options Review Panel was appointed by SaskPower to seek public views on future demand and supply options. The review is now complete and a final report has been released on the panel's findings. The panel made several recommendations, including recommendations related to NUGs. They are as follows:

- A limit of 125 MW be placed initially on non-utility generators;
- The government of Saskatchewan should proceed immediately to establish an independent tribunal which will provide an arbitrator function between SaskPower and independent power producers. SaskPower and the tribunal should develop a highly visible framework,

Table 14.4. Minor utility energy generation by fuel type, 1991

	Conventional Thermal							
	Coal	Oil	Gas	Sub-total	Nuclear	Hydro	Other	Total
					(GW.h)			
Nfld.	0	8	0	8	0	800	0	808
P.E.I.	0	0	0	0	0	0	0	0
N.S.	0	0	0	0	0	0	0	0
N.B.	0	0	0	0	0	140	0	140
Quebec	0	0	0	0	0	4 200	0	4 200
Ontario	0	0	0	0	0	1 630	0	1 630
Manitoba	0	0	0	0	0	0	0	0
Sask.	0	0	0	0	0	0	0	0
Alberta	0	0	0	0	0	0	0	0
B.C.	0	0	0	0	0	825	0	825
Yukon	0	0	0	0	0	0	0	0
N.W.T.	0	0	0	0	0	0	0	0
Canada	0	8	0	8	0	7 595	0	7 603

Source: Electric Power Branch, National Energy Board, March 1992, and Electricity Branch, Energy, Mines and Resources Canada, March 1992.

> which would include an avoided cost policy, to facilitate incorporation into Saskatchewan's electrical energy system.

SaskPower is reviewing the panel's recommendations and will be responding shortly. It is likely that a new policy will emerge out of this review.

As indicated in Table E3, the power purchase rates of the major utilities appear to be based on avoided-cost principles. Thus the cost of non-utility generation should be at or below the cost of future facilities required by major utilities for the supply of electricity to their customers. Although Manitoba Hydro presently does not have a power purchase policy in place, it has indicated that it would follow the principle of avoided costs as well.

NUG POTENTIAL IN CANADA

This section presents the major electric utilities' forecasts of non-utility generation expected to come into service over the 19-year planning period 1992-2010. Based on equipment costs, fuel costs, interest rates, return on investment, and estimates of purchase rates, the major utilities have derived forecasts of the NUG potential that is economic from the NUG developer's perspective. The forecasts of NUG capacity are grouped into three categories: hydraulic, co-generation and other thermal.

Table 14.5 summarizes attainable NUG capacity for the period 1992-2010. According to estimates prepared by the major utilities, a total of 5393 MW of NUG capacity will be attainable by the year 2000. Of this total, co-generation fuelled mainly by natural gas will account for 69 per cent, followed by other thermal (waste fuelled) with 17 per cent, and small hydro with 14 per cent. By 2000, it is projected that the majority of new non-utility generators will be located in Ontario (58 per cent), Quebec (16 per cent), and British Columbia (13 per cent).

Table 14.5. Projections of attainable non-utility generating capacity

	1992	2000			2010		
		Hydraulic	Cogeneration	Other Thermal	Hydraulic	Cogeneration	Other Thermal
				(MW)			
Nfld.	195	239	0	6	239	0	6
N.S.	0	8	21	33	8	21	28
N.B.	165	18	147	100	18	147	100
Quebec	23	140	396	328	300	600	400
Ontario	598	266	2 733	108	356	3 453	178
Sask.	0	0	0	15	0	0	15
Alberta	21	0	0	125	2 100	0	0
B.C.	26	97	402	217	715*	0	1 000
Canada	1 028	768	3 699	926	3 736	4 221	1 727

** May be developed by B.C. Hydro or NUG.*

Source: Canadian electric utilities, March 1992.

By the end of 2010, it is estimated that total attainable NUG capacity will be about 9684 MW. Again, co-generators fuelled by natural gas will have the major share with 44 per cent, followed by small hydro with 38 per cent, and other thermal with 18 per cent. By 2010, it is expected that approximately 41 per cent of NUG facilities will be located in Ontario.

While NUG projects have their own environmental impacts, there tends to be public preference for this type of generation. This is because NUG projects are smaller, localized and more dispersed so that, on an individual basis, environmental and community impacts may be less than those of conventional generation options. In comparison, conventional generation projects are larger, more centralized, and take a longer time to construct.

The future development of NUG, however, will depend on profitability. Achieving an acceptable rate of return on investment is a critical factor affecting the viability of a non-utility generation project. According to Ontario Hydro's estimate, rates of return on investment in the range of 15 per cent to 20 per cent are required by a developer before a NUG project will be undertaken.

The rate of return, and thus the level of NUG development, is directly linked to the purchase rate offered by a major utility. As indicated in Table E3, current purchase rates offered by the major utilities are generally based on avoided-cost principles. In definition, the avoided cost is the cost that major utilities would incur in providing the same electricity supply as that of the non-utility generator. In practice, however, avoided costs can be difficult to calculate.

At present, the amount of electricity generated in Canada from independent power producers is relatively small. However, in the past few years, electricity planners have begun to give NUG a much greater emphasis, especially where such generation is produced from renewable or waste resources, or at higher efficiencies than conventional generators. It is expected that NUG will play a far more active role in the development of Canada's electricity service in the next decade or two.

Table 14.6. Projections of attainable non-utility generation

	1992	2000			2010		
		Hydraulic	Cogeneration	Other Thermal	Hydraulic	Cogeneration	Other Thermal
				(GW.h)			
Nfld.	1 358	1 581	0	40	1 581	0	40
N.S.	2	48	168	248	48	168	210
Quebec	143	797	2 775	2 500	1 970	4 205	3 045
Ontario	3 932	1 914	18 985	710	2 027	23 891	1 169
Sask.	0	0	0	85	0	0	0
B.C.	68	364	3 080	1 575	1 770	0	0
Canada	5 503	4 304	25 008	5 158	7 396	28 264	4 464

Source: Canadian electric utilities, March 1992.

APPENDIX A

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Table A1. Installed capacity and electrical energy consumption in Canada, 1920-1991

	INSTALLED CAPACITY					Electrical					
	Thermal					Energy	Average	Peak			
Year	Conventional	Nuclear	Sub-Total	Hydro	Total	Consumption	Demand	Demand	Reserve Margin		Load Factor
	(MW)					(GW.h) (a)	(MW) (b)	(MW) (c)	(MW) (d)	(%)	(%) (e)
1920	300	-	300	1 700	2 000	-	-	-	-	-	-
1930	400	-	400	4 300	4 700	19 468	2 222	-	-	-	-
1940	500	-	500	6 200	6 700	33 062	3 774	-	-	-	-
1950	900	-	900	8 900	9 800	55 037	6 283	-	-	-	-
1955	2 100	-	2 100	12 600	14 700	81 000	9 247	12 536	2 164	17	74
1960	4 392	-	4 392	18 643	23 035	109 304	12 478	17 264	5 771	33	72
1965	7 557	20	7 577	21 771	29 348	144 165	16 457	24 167	5 181	21	68
1970	14 287	240	14 527	28 298	42 826	202 337	23 098	34 592	8 234	24	67
1975	21 404	2 666	24 070	37 282	61 352	265 955	30 360	46 187	15 165	33	66
1976	23 039	3 466	26 505	39 488	65 993	284 829	32 515	49 527	16 456	33	66
1977	24 699	5 066	29 765	40 810	70 575	299 673	34 209	52 001	18 574	36	66
1978	26 154	5 866	32 020	41 898	73 918	316 435	36 123	54 106	19 812	37	67
1979	27 353	5 866	33 219	44 009	77 228	323 465	36 925	55 699	21 529	39	66
1980	28 363	5 866	34 229	47 770	81 999	340 068	38 821	59 167	22 832	39	66
1981	28 493	5 600	34 093	49 216	83 308	346 333	39 536	59 237	24 071	41	67
1982	28 957	6 547	35 504	50 007	85 511	345 115	39 397	62 417	23 094	37	63
1983	30 447	7 771	38 218	51 274	89 492	359 838	41 077	66 866	22 626	34	61
1984	30 427	9 813	40 240	54 949	95 189	385 516	44 009	65 798	29 391	45	67
1985	30 475	10 664	41 139	55 880	97 019	406 859	46 445	71 235	25 784	36	65
1986	30 979	11 364	42 343	57 731	100 074	423 027	48 153	70 364	29 710	42	68
1987	30 800	12 528	43 328	57 945	101 273	439 710	50 195	77 923	23 350	30	64
1988	30 525	12 593	43 118	57 937	101 055	462 948	52 848	78 961	22 094	28	67
1989	30 892	12 603	43 495	58 465	101 960	474 358	53 971	78 200	23 760	30	69
1990	31 173	13 052	44 225	58 722	102 947	465 395	53 127	78 302	24 645	31	68
1991p	31 324	13 052	44 376	60 255	104 631	470 895	53 755	82 863	21 768	26	65

(a) *1920-55: Figures are approximate, computed using actual Statistics Canada data for stations generating energy for sale to which have been added estimates for stations generating entirely for own use. 1920-55: Canadian Energy Prospects (Royal Commission on Canada's Economic Prospects) John Davis, 1957.*
1956-81: Statistics Canada Publication 57-202.

(b) *Average Demand = Energy Consumption/8760 (hrs/yr).*

(c) *Statistics Canada Publication 57-204.*

(d) *Reserve margin =* $\frac{\text{(Installed capacity - Peak demand)}}{\text{Peak demand}}$

(e) *Load Factor = Average demand /Peak demand.*

p *Preliminary figures.*

Source: Statistics Canada and Energy, Mines and Resources Canada.

Table A2. Installed generating capacity, 1991

	Hydro	Nuclear	Conventional Thermal	Total	% of Canadian Total
			(MW)		
Newfoundland	6 650	0	812	7 462	7.19
Prince Edward Island	0	0	122	122	.12
Nova Scotia	386	0	1 920	2 306	2.08
New Brunswick	903	680	1 960	3 543	3.39
Quebec	28 091	685	1 103	29 879	27.80
Ontario	7 143	11 687	13 899	32 729	32.34
Manitoba	4 533	0	413	4 946	4.31
Saskatchewan	836	0	2 010	2 846	2.74
Alberta	734	0	7 242	7 976	7.68
British Columbia	10 849	0	1 648	12 497	12.04
Yukon	77	0	49	126	.12
Northwest Territories	53	0	146	199	.19
Canada (Totals as of December 31/91)	60 255	13 052	31 324	104 631	100.00
Percentage of total	57.15	10.00	29.85	100.00	
Net additions during 1991	1 534	0	150	1 684	

Source: Energy, Mines and Resources Canada.

Table A3. Conventional thermal capacity by principal fuel type, 1991* (MW)

	Steam					Gas Turbine			Internal Combustion			All Conventional Thermal				
	Coal	Oil	Gas	Other	Total	Oil	Gas	Total	Oil	Gas	Total	Coal	Oil	Gas	Other**	Total
Nfld.	0	555	0	5	560	170	0	170	82	0	82	0	807	0	5	812
P.E.I.	20	50	0	0	70	41	0	41	11	0	11	20	102	0	0	122
N.S.	1 312	382	0	19	1 713	205	0	205	2	0	2	1 312	589	0	19	1 920
N.B.	418	1 391	0	87	1 896	48	0	48	16	0	16	418	1 455	0	87	1 960
Que.	0	614	8	5	627	363	0	363	113	0	113	0	1 090	8	5	1 103
Ont.	10 653	2 200	256	91	13 200	506	181	687	4	8	12	10 653	2 710	445	91	13 899
Man.	369	0	4	23	396	0	0	0	17	0	17	369	17	4	23	413
Sask.	1 531	21	279	22	1 853	0	155	155	2	0	2	1 531	23	434	22	2 010
Alta	4 861	0	1 546	336	6 743	0	464	464	17	18	35	4 861	17	2 028	336	7 242
B.C.	0	66	963	370	1 399	100	51	151	76	22	98	0	242	1 036	370	1 648
Yukon	0	0	0	0	0	0	0	0	49	0	49	0	49	0	0	49
N.W.T.	0	0	0	0	0	0	20	20	126	0	126	0	126	20	0	146
Canada	19 164	5 279	3 056	958	28 457	1 433	871	2 304	515	48	563	19 164	7 227	3 975	958	31 324

* *Preliminary figures as of December 31, 1991.*

** *Mainly wood wastes and black liquor.*

Numbers may not total due to rounding.

Source: Electricity Branch, Energy, Mines and Resources Canada.

Table A4. Electrical energy production by principal fuel type, 1991

	Conventional Thermal*								% of Total Generation	% Generated by	
	Coal	Oil	Gas	Sub-Total	Nuclear	Hydro	Other	Total		Utilities	Industry
	------------------------	------------------------	------------------------	------(GW.h)------	------------------------	------------------------	------------------------	------------------------			
Nfld.	0	1 523	0	1 523	0	35 445	0	36 968	7.56	98.67	1.34
P.E.I.	0	71	0	71	0	0	0	71	.02	100.00	.00
N.S.	5 855	2 353	0	8 208	0	1 034	143	9 385	1.92	95.98	4.02
N.B.	1 150	5 937	0	7 087	5 440	2 971	261	15 759	3.22	94.98	5.02
Que.	0	504	0	504	3 910	137 867	0	142 281	29.08	87.68	12.32
Ont.	29 268	1 096	1 876	32 240	70 773	37 418	240	140 671	28.75	97.08	2.92
Man.	265	20	13	298	0	22 543	30	22 871	4.67	99.72	.28
Sask.	8 644	18	533	9 195	0	4 205	176	13 576	2.77	96.96	3.04
Alta.	36 836	0	4 181	41 017	0	2 030	674	43 721	8.94	92.30	7.70
B.C.	0	550	1 201	1 751	0	60 149	1 081	62 981	12.87	79.02	20.98
Yukon	0	55	0	55	0	410	0	465	0.10	100.00	.00
N.W.T.	0	222	0	222	0	256	0	478	0.10	94.97	5.03
Canada	82 018	12 349	7 804	102 171	80 123	304 328	2 605	489 227	100.00	91.75	8.25

* *The conventional thermal breakdown is estimated.*

Source: Statistics Canada and Energy, Mines and Resources Canada.

Table A5. Provincial electricity imports and exports (GW.h) 1991

Province	Year	Interprovincial Trade			International Trade*			Total Net Exports
		Exports	Imports	Net Exports	Exports	Imports	Net Exports	
Newfoundland	1991	26 366	-	26 366	-	-	-	26 366
	1990	26 164	-	26 164	-	-	-	26 164
	1989	24 367	-	24 367	-	-	-	24 367
	1988	30 727	-	30 727	-	-	-	30 727
	1987	30 393	-	30 393	-	-	-	30 393
Prince Edward Island	1991	-	690	-690	-	-	-	-690
	1990	-	672	-672	-	-	-	-672
	1989	-	622	-622	-	-	-	-622
	1988	-	486	-486	-	-	-	-486
	1987	-	483	-483	-	-	-	-483
Nova Scotia	1991	50	444	-394	-	-	-	-394
	1990	116	365	-249	-	-	-	-249
	1989	341	441	-100	-	-	-	-100
	1988	166	186	-20	-	-	-	-20
	1987	82	659	-577	-	-	-	-577
New Brunswick	1991	2 542	3 433	-891	3 092	79	3 013	2 122
	1990	2 153	2 775	-622	4 277	162	4 115	3 493
	1989	2 014	2 307	-293	4 640	264	4 376	4 083
	1988	981	2 856	-1 875	5 191	190	5 001	3 126
	1987	1 164	6 922	-5 758	6 141	266	5 875	117
Quebec	1991	4 112	27 883	-23 771	5 959	730	5 229	-18 542
	1990	3 349	27 414	-24 065	3 403	1 188	2 215	-21 851
	1989	2 998	25 399	-22 401	5 438	1 001	4 437	-17 964
	1988	4 979	31 079	-26 100	11 863	86	11 777	-14 323
	1987	12 782	30 427	-17 645	16 401	-	16 401	-1 244
Ontario	1991	109	2 211	-2 102	4 771	3 674	1 097	-1 005
	1990	140	2 326	-2 186	2 050	13 339	-11 289	-13 475
	1989	91	2 335	-2 244	4 314	7 864	-3 550	-5 794
	1988	65	2 827	-2 762	7 439	2 611	4 828	2 066
	1987	16	6 992	-6 976	8 497	2 113	6 384	-592
Manitoba	1991	2 634	975	1 659	3 478	289	3 189	4 848
	1990	2 694	1 053	1 641	2 050	991	1 059	2 700
	1989	2 474	1 126	1 348	1 284	1 447	-163	1 185
	1988	1 908	1 126	782	628	1 969	-1 341	-559
	1987	2 311	1 220	1 091	3 461	512	2 949	4 040

Table A5. Provincial electricity imports and exports (GW.h) 1991 (continued)

		Interprovincial Trade			International Trade*			
Province	Year	Exports	Imports	Net Exports	Exports	Imports	Net Exports	Total Net Exports
Saskatchewan	1991	998	1 268	-270	148	120	28	-242
	1990	1 086	1 152	-66	121	107	14	136
	1989	1 130	1 213	-83	72	123	-51	-134
	1988	1 109	1 369	-260	57	315	-258	-518
	1987	1 222	1 262	-40	113	84	29	-11
Alberta	1991	1 064	678	386	-	3	-3	383
	1990	1 336	500	836	-	3	-3	833
	1989	2 519	258	2 261	-	3	-3	2 258
	1988	1 218	369	849	-	-	-	849
	1987	710	526	184	-	2	-2	182
British Columbia	1991	655	948	-293	7 070	1 324	5 746	5 453
	1990	461	1 242	-781	6 228	1 991	4 237	3 456
	1989	242	2 477	-2 235	6 341	2 024	4 317	2 082
	1988	364	1 219	-855	8 851	1 132	7 719	6 864
	1987	521	710	-189	12 815	493	12 322	12 133
Yukon	1991	-	-	-	-	-	-	-
	1990	-	-	-	-	-	-	-
	1989	-	-	-	-	-	-	-
	1988	-	-	-	-	-	-	-
	1987	-	-	-	-	-	-	-
Northwest Territories	1991	-	-	-	-	-	-	-
	1990	-	-	-	-	-	-	-
	1989	-	-	-	-	-	-	-
	1988	-	-	-	-	-	-	-
	1987	-	-	-	-	-	-	-
Canada	1991	-	-	-	24 518	6 219	18 299	18 299
	1990	-	-	-	18 130	17 781	349	349
	1989	-	-	-	22 089	12 724	9 365	9 365
	1988	-	-	-	34 029	6 305	27 724	27 724
	1987	-	-	-	47 428	3 470	43 958	43 958

* *Includes exchanges.*

Source: Statistics Canada.

Table A6. Canadian electricity exports by exporter and importer, 1991*

Exporter	Importer	Revenue ($000)	Quantity (GW.h)
Fraser Inc.	Fraser Paper Ltd. (Maine)	18 652	327
Maine & New Brunswick Electrical Power Co. Ltd.	Maine Public Service Co. (Maine)	2 725	104
NB Power	Maine Public Service Co. (Maine)	3 307	128
NB Power	Eastern Maine Electric Cooperative Inc. (Maine)	4 530	63
NB Power	Maine Electric Power (Maine)	12 475	372
NB Power	Central Maine Power Co. (Maine)	2 582	140
NB Power	Bangor Hydro-Electric Co. (Maine)	3 432	129
NB Power	Massachusetts Municipal Wholesale Electric Co. (Massachusetts)	39 647	772
NB Power	Boston Edison Co. (Massachusetts)	39 873	704
NB Power	Commonwealth Electric Co. (Massachusetts)	9 968	176
Hydro-Québec	Vermont Joint Owners (Vermont)	24 368	519
Hydro-Québec	Vermont Dept. of Public Service (Vermont)	32 233	860
Hydro-Québec	Vermont Marble Company (Vermont)	84	2
Hydro-Québec	New England Power Pool (New England)	72 026	2 982
Hydro-Québec	Niagara Mohawk Power Corp. (New York)	2 377	81
Hydro-Québec	New York Power Authority (New York)	32 086	1 465
Cornwall Electric	Niagara Mohawk Power Corp. (New York)	261	11
Canadian Niagara	Niagara Mohawk Power Corp. (New York)	5 210	397
Ontario Hydro	Vermont Dept. of Public Service (Vermont)	1 858	23
Ontario Hydro	Niagara Mohawk Power Corp. (New York)	21 325	760
Ontario Hydro	New York Power Authority (New York)	25 869	974
Ontario Hydro	New York Power Pool (New York)	8 325	2 498
Ontario Hydro	Detroit Edison Co. (Michigan)	2 347	107
Manitoba Hydro	Northern States Power Co. (Minnesota)	40 878	2 626
Manitoba Hydro	Otter Tail Power Co. (Minnesota)	8 817	482
Manitoba Hydro	United Power Association (Minnesota)	72	4
Manitoba Hydro	Minnesota Power & Light Co. (Minnesota)	3 552	168
Manitoba Hydro	Minnkota Power Cooperative Inc. (North Dakota)	4 063	195
Saskatchewan Power Corp.	Basin Electric Power Cooperative (North Dakota)	685	148
Cominco Ltd.	Puget Sound Power & Light Co. (Washington)	102	6
Cominco Ltd	Washington Water Power Co. (Washington)	225	12
Cominco Ltd.	Portland General Electric Co. (Oregon)	944	59
Cominco Ltd.	Pacific Power & Light Co. (Oregon)	17	2
Cominco Ltd.	Montana Power Co. (Montana)	138	10
Comonco Ltd.	Sierra Pacific Power Co. (Nevada)	114	6
Cominco Ltd.	Idaho Power Co. (Idaho)	151	9
Cominco Ltd.	Bonneville Power Administration (California)	1 490	273
B.C. Hydro	Seattle City Light (Washington)	414	16
B.C. Hydro	Puget Sound Power & Light Co. (Washington)	1 697	49

Table A6. Canadian electricity exports by exporter and importer, 1991* (continued)

Exporter	Importer	Revenue ($000)	Quantity (GW.h)
B.C. Hydro	Washington Water Power Co. (Washington)	2 532	105
B.C. Hydro	Portland General Electric Co. (Oregon)	22 268	1 207
B.C. Hydro	Pacific Power & Light Co. (Oregon)	947	55
B.C. Hydro	Idaho Power Co. (Idaho)	1 690	135
B.C. Hydro	Montana Power Co. (Montana)	133	15
B.C. Hydro	Bonneville Power Administration (California)	64 930	4 229
B.C. Hydro	City of Los Angeles (California)	31 160	1 080
B.C. Hydro	Sierra Pacific Power Co. (Nevada)	26	2
B.C. Hydro	Snohomism PUP	2	80

N = negligible

** Excludes border accommodations.*

Source: Energy, Mines and Resources Canada.

Table A7. Generation capacity by type (MW)

	Steam	Gas Turbine	Internal Combusti[illegible]	Nuclear	Total Thermal	Hydro	Total
NEWFOUNDLAND							
Total end 1990	559.60	170.39	81.85	-	811.84	6 649.79	7 461.63
Changes 1991	-	-	-	-	-	-	-
Total end 1991	559.60	170.39	81.85	-	811.84	6 649.79	7 461.63
Additions proposed							
1993	-	25.00	-	-	25.00	-	25.00
1994	-	-	-	-	-	6.00	6.00
Total end 1993	559.60	195.39	81.85	-	836.84	6 655.79	7 492.63
PRINCE EDWARD ISLAND							
Total end 1990	70.50	40.45	11.14	-	122.09	-	122.09
Changes 1991	-	-	-	-	-	-	-
Total end 1991	70.50	40.45	11.14	-	122.09	-	122.09
NOVA SCOTIA							
Total end 1990	1 563.62	205.00	1.50	-	1 770.12	386.36	2 156.48
Changes 1991	150.00	-	-	-	-	-	150.00
Total end 1991	1 713.62	205.00	1.50	-	1 920.12	386.36	2 306.48
Additions proposed							
1993	165.00	-	-	-	165.00	-	165.00
2001	165.00	-	-	-	165.00	-	165.00
2006	165.00	-	-	-	165.00	-	165.00
2008	165.00				165.00	-	165.00
2011	165.00				165.00	-	165.00
Total end 2011	2 538.62	205.00	1.50	-	2 745.12	386.36	3 131.48

Table A7. Generation capacity by type (MW) (continued)

	Steam	Gas Turbine	Internal Combustion	Nuclear	Total Thermal	Hydro	Total
NEW BRUNSWICK							
Total end 1990	1 894.98	48.38	16.34	680.00	2 639.70	903.03	3 542.73
Changes 1991	-	-	-	-	-	-	-
Total end 1991	1 894.98	48.38	16.34	680.00	2 639.70	903.03	3 542.73
Additions proposed							
1993	440.00	-	-	-	440.00	-	440.00
1999	-	100.00	-	-	100.00	-	100.00
2000	-	100.00	-	-	100.00	-	100.00
2001	-	100.00	-	-	100.00	-	100.00
2004	440.00	-	-	-	440.00	-	440.00
Total end 2004	2 774.98	348.38	16.34	680.00	3 819.70	903.03	4 722.73
QUEBEC							
Total end 1990	627.65	362.88	112.99	685.00	1 788.52	27 085.44	28 873.96
Changes 1991	-	-	-		-	1 006.00	1 006.00
Total end 1991	627.65	362.88	112.99	685.00	1 788.52	28 091.44	29 879.96
Additions proposed							
1992	-	195.00	-	-	195.00	1 006.00	1 201.00
1993	-	195.00	-	-	195.00	712.00	907.00
1994	-	-	-	-	-	1 253.00	1 253.00
1995	-	-	-	-	-	656.00	656.00
1996	-	-	-	-	-	289.00	289.00
1997	-	-	-	-	-	465.00	465.00
1998	-	-	-	-	-	692.00	692.00
1999	-	-	-	-	-	1 671.00	1 671.00
2000	-	-	-	-	-	824.00	824.00
2001	-	-	-	-	-	540.00	540.00
2002	-	-	-	-	-	350.00	350.00
2003	-	-	-	-	-	560.00	560.00
2004	-	-	-	-	-	478.00	478.00
2005						282.00	282.00
2006	600.00	-	-	-	600.00	1 224.00	1 824.00
2007	-	400.00	-	-	400.00	348.00	748.00
2008		300.00			300.00	249.00	549.00
2009	-	300.00	-	-	300.00	282.00	582.00
2010	-	100.00	-	-	100.00	703.00	803.00
Total end 2010	1 227.65	1 852.88	112.99	685.00	3 878.52	40 675.44	44 553.96

Table A7. Generation capacity by type (MW) (continued)

	Steam	Gas Turbine	Internal Combustion	Nuclear	Total Thermal	Hydro	Total
ONTARIO							
Total end 1990	13 200.07	686.65	11.77	11 687.00	25 585.49	7 147.34	32 732.83
Changes 1991	-	-	-	-	-	-	-
Total end 1991	13 200.07	686.65	11.77	11 687.00	25 585.49	7 147.34	32 732.83
Additions proposed							
1992	-	-	-	1 762.00	1 762.00	-	1 762.00
1993	-	-	-	881.00	881.00	10.00	891.00
Total end 1993	13 200.07	686.65	11.77	14 330.00	28 228.49	7 157.34	35 385.83
MANITOBA							
Total end 1990	395.80	-	17.25	-	413.05	4 000.86	4 413.91
Changes 1991	-	-	-	-	-	532.00	532.00
Total end 1991	395.80	-	17.25	-	413.05	4 532.86	4 945.91
Additions proposed							
1992	-	-	-	-	-	399.00	399.00
2001	-	-	-	-	-	556.00	556.00
2002	-	-	-	-	-	556.00	556.00
2003	-	-	-	-	-	278.00	278.00
2013	-	-	-	-	-	175.00	175.00
2014	-	-	-	-	-	175.00	175.00
Total end 2014	395.80	-	17.25	-	413.05	6 671.86	7 084.91
SASKATCHEWAN							
Total end 1990	1 853.21	154.92	2.18	-	2 010.31	835.86	2 846.17
Changes 1991	-	-	-	-	-	-	-
Total end 1991	1 853.21	154.92	2.18	-	2 010.31	835.86	2 846.17
Additions proposed							
1992	300.00	-	-	-	300.00	-	300.00
2000	-	50.00	-	-	50.00	-	50.00
Total end 2000	2 153.21	204.92	2.18	-	2 360.31	835.86	3 196.17

Table A7. Generation capacity by type (MW) (continued)

	Steam	Gas Turbine	Internal Combustion	Nuclear	Total Thermal	Hydro	Total
ALBERTA							
Total end 1990	6 743.12	464.10	34.72	-	7 241.94	733.70	7 975.64
Changes 1991	-	-	-	-	-	-	-
Total end 1991	6 743.12	464.10	34.72	-	7 241.94	733.70	7 975.64
Additions proposed							
1993	-	34.00	-	-	34.00	-	34.00
1994	406.00	-	-	-	406.00	-	406.00
1996	30.00	-	-	-	30.00	-	30.00
Total end 1996	7 179.12	498.10	34.72	-	7 711.94	733.70	8 445.64
BRITISH COLUMBIA							
Total end 1990	1 399.16	150.70	98.18	-	1 648.04	10 849.07	12 497.11
Changes 1991	-	-	-	-	-	-	-
Total end 1991	1 399.16	150.70	98.18	-	1 648.04	10 849.07	12 497.11
Additions proposed							
2009	-	-	-	-	-	380.00	380.00
Total end 2009	1 399.16	150.70	98.18	-	1 648.04	11 229.07	12 877.11
YUKON							
Total end 1990	-	-	48.99	-	48.99	76.75	125.74
Changes 1991	-	-	-	-	-	-	-
Total end 1991	-	-	48.99	-	48.99	76.75	125.74
NORTHWEST TERRITORIES							
Total end 1990	-	19.50	126.02	-	145.52	53.36	198.88
Changes 1991	-	-	-	-	-	-	-
Total end 1991	-	19.50	126.02	-	145.52	53.36	198.88
Additions proposed							
1992	-	-	1.72	-	1.72	-	1.72
Total end 1992	-	19.50	127.74	-	147.24	53.36	200.60

Table A7. Generation capacity by type (MW) (continued)

	Steam	Gas Turbine	Internal Combustion	Nuclear	Total Thermal	Hydro	Total
CANADA							
Total end 1990	28 307.72	2 302.97	562.91	13 052.00	44 225.60	58 721.58	102 947.17
Changes 1991	150.00	-	-	-	150.00	1 534.00	1 684.00
Total end 1991	28 457.72	2 302.97	562.91	13 052.00	44 375.60	60 255.58	104 631.18
Additions proposed							
1992	300.00	196.72	-	1762.00	2 258.72	1 405.00	3 663.72
1993	605.00	254.00	-	881.00	1 740.00	722.00	2 462.00
1994	406.00	-	-	-	406.00	1 259.00	1 665.00
1995	-	-	-	-	-	656.00	656.00
1996	30.00	-	-	-	30.00	289.00	319.00
1997	-	-	-	-	-	465.00	465.00
1998	-	-	-	-	-	692.00	692.00
1999	-	100.00	-	-	100.00	1 671.00	1 771.00
2000	-	150.00	-	-	150.00	824.00	974.00
2001	165.00	100.00	-	-	265.00	1 096.00	1 361.00
2002	-	-	-	-	-	906.00	906 .00
2003	-	-	-	-	-	838.00	838.00
2004	440.00	-	-	-	440.00	478.00	918.00
2005	-	-	-	-	-	282.00	282.00
2006	765.00	-	-	-	765.00	1 224.00	1 989.00
2007	-	400.00	-	-	400.00	34800	748.00
2008	165.00	300.00	-	-	465.00	249.00	714.00
2009	-	300.00	-	-	300.00	662.00	962.00
2010	-	100.00	-	-	100.00	703.00	803.00
2011	165.00	-	-	-	165.00	-	165.00
2012	-	-	-	-	-	-	-
2013	-	-	-	-	-	175.00	175.00
2014	-	-	-	-	-	175.00	175.00
Total end 2014	31 498.72	4 203.69	562.91	15 695.00	51 960.32	75 374.58	127 334.90

Source: Energy, Mines and Resources Canada.

Table A8. Installed generating capacity expansion in Canada by station. Major 1991 additions and 1992 - 2014 projections

Province and Station	Type*	1991 Additions	Completion Date	Additions Proposed	Status*	Plant Capacity
		(MW)		(MW)		(MW)
NEWFOUNDLAND						
Port aux Basques	GT(o)		1993	25	C	25
Rose Blanche	H		1993	6	C	6
PRINCE EDWARD ISLAND						
Charlottetown	GT(o)		1996	24	P	24
NOVA SCOTIA						
Trenton	S(c)	150				
Point Aconi	S(c)		1993	165	C	
			2001	165	P	
			2006	165	P	495
CFB	S(c)		2008	165	P	
			2011	165	P	330
NEW BRUNSWICK						
Belledune	S(c)		1993	440	C	
			2004	440	P	880
Combustion Turbine	GT(o)		1999	100	P	100
Combustion Turbine	GT(o)		2000	100	P	100
Combustion Turbine	GT(o)		2001	100	P	100
QUEBEC						
La Forge-1	H		1993	2 x 137	P	
			1994	3 x 136	P	817
			1994	135	p	817
La Forge-2	H		1996	145	P	
			1996	144	P	289
Manic-1[1]	H		2006	134	P	134
Brisay	H		1993	2 X 191	C	382

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[1] *Uprating of existing units*

Table A8. Installed generating capacity expansion in Canada by station. Major 1991 additions and 1992 - 2014 projections (continued)

Province and Station	Type*	1991 Additions	Completion Date	Additions Proposed	Status*	Plant Capacity
		(MW)		(MW)		(MW)
QUEBEC (cont'd)						
Outardes 4	H		2002	350	P	350
Outardes 3	H		2004	2 X 239	P	478
Outardes 2	H		2005	282	P	282
Manic-2	H		1999	322	P	1 378
Manic-3	H		1998	2 x 301	P	1 803
Manic-5[1]	H	56				
			1992	56	C	
			1993	56	C	
			1994	56	C	2 052
LG-1	H		1994	3 x 109	P	
			1994	2 x 110	P	
			1995	4 x 109	P	
			1995	2 x 110	P	1 312
LG-2A	H	950				
			1992	2 x 317	C	
			1992	316	C	7 228
Ste-Marguerite-3	H		2006	2 x 393	P	786
Grande-Baleine-1	H		1999	2 x 411	P	
			1999	412	P	
			2000	2 x 412	P	2 058
Grande Baleine-2	H		2001	3 x 180	P	540
Grande Baleine-3	H		2003	187	P	
			2003	188	P	560
			2003	185	P	
Eastmain-1	H		1997	3 x 155	P	465
Future peaking	GT(d)		2007	400	P	
			2008	300	P	
			2009	300	P	
			2010	100	P	1 100
Bécancour	H		1992	195	C	
			1993	195	C	390
Thermique Base	S(o)		2006	600	P	600
Rapid des Coeurs	H		2007	2 x 174	P	348
Chutes Chaudieres	H		2008	125	P	
			2008	124	P	249

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[1] *Uprating of existing units*

Table A8. Installed generating capacity expansion in Canada by station. Major 1991 additions and 1992 - 2014 projections (continued)

Province and Station	Type*	1991 Additions	Completion Date	Additions Proposed	Status*	Plant Capacity
		(MW)		(MW)		(MW)
QUEBEC (cont'd)						
Ashuapmushuan-4	H		2006	303	P	303
R11	H		2009	282	P	
	H		2010	80	P	362
R10	H		2010	291	P	291
B5	H		2010	2 x 166	P	332
Mercier	H		1998	90	P	90
Kipawa	H		1999	115	P	115
ONTARIO						
Darlington	N		1992	1 762	C	
			1993	881	C	3 524
MANITOBA						
Limestone	H	4 x 133				
			1992	3 x 133	C	1 330
Conawapa	H		2001	4 x 139	P	
			2002	4 x 139	P	
			2003	2 x 139	P	1 390
Wuskwatim	H		2013	2 x 87.5	P	
			2014	2 x 87.5	P	350
SASKATCHEWAN						
Shand	S(c)		1992	300	C	300
Future peaking 1	GT(g)		2000	50	P	50
ALBERTA						
Genesee	S(c)		1994	406	C	812
Medicine Hat	GT(g)		1993	34	C	34
	S(g)		1996	30	P	30

Table A8. Installed generating capacity expansion in Canada by station. Major 1991 additions and 1992 - 2014 projections (continued)

Province and Station	Type*	1991 Additions (MW)	Completion Date	Additions Proposed (MW)	Status*	Plant Capacity (MW)
BRITISH COLUMBIA						
Waneta	H		2009	2 x 190	P	380
YUKON						
Dawson	IC		1993	1.0	P	5.2
McIntyre	H		1992	0.8	P	1.5
Whitehorse	IC		1992	4.5	C	
	IC		1994	4.5	P	31
NORTHWEST TERRITORIES						
Copper Mine	IC		1992	0.72	C	0.72
Fort Good Hope	IC		1992	2 x 0.5	C	1.00

*** Legend**

H	Hydro	IC	Internal combustion
S(c)	Steam (coal)	GT	Gas turbine
N	Nuclear	I	Installed
P	Planned	C	Under construction
GT(o)	Gas turbine (oil)		
GT(g)	Gas turbine (natural gas)		
GT(d)	Gas turbine (diesel)		

Source: Energy, Mines and Resources Canada.

APPENDIX B

B1. Chronology of Canadian electrical developments and achievements 133

B2. Chronology of regional interconnections 137

B1. Chronology of Canadian Electrical Developments and Achievements

1846	Toronto, Hamilton, Niagara, and St. Catharines Electro-Magnetic Telegraph Company formed.
1847	Montreal Telegraph Company formed with lines from Quebec City to Toronto.
1858	Message sent from Queen Victoria to U.S. President Buchanan via first trans-Atlantic cable from Valentia, Ireland, to White Sands Bay, Newfoundland.
1873	Davis House in Winnipeg used arc light to illuminate front of building.
1876	Alexander Graham Bell made first long-distance telephone call from Paris, Ontario, to Brantford, Ontario, via battery power in Toronto — a total distance of 218 km.
1878	Robert McMicking began experiments with electric street lighting in Victoria.
1878	American Electric and Illuminating Company formed in Montreal — Canada's first electric light company.
1879	British Columbia Electric Railway launched.
1879	Electric light demonstrated in McConkey's Restaurant, Toronto.
1881	Toronto's first electric generator built by J.J. White. T. Eaton was the first customer.
1881	Ahearn & Soper of Ottawa introduced electric light for industry.
1882	One of North America's first hydroelectric generating facilities constructed at Chaudière Falls on the Ottawa River.
1882	F. Nicholls formed Toronto Electric Supply Company (forerunner of Canadian General Electric).
1883	Canada's first electric lighting plant started at Canadian Cottons, Cornwall, Ontario, by Thomas Edison.
1883	Toronto's first electric railway built by J.J. Wright.
1883	Canada's first street lights installed in Hamilton, Ontario.
1884	Canada's first electric utility set up in Pembroke, Ontario, by R.B. McAllister.
1884	Electric street lighting installed in Montreal and Toronto.
1885	First Canadian electric streetcar enters service in Toronto.
1885	St. John's Electric Light Company produced power for street and shop lighting.
1886	Victoria Electric Lighting Company (forerunner of B.C. Electric and B.C. Hydro) formed.
1887	Hydroelectric plant built at Twelve Mile Creek, near Welland, Ontario.
1887	Canadian engineer Sir Sandford Fleming completed Pacific cable.
1889	Calgary sawmill run by electricity; electric lights in Calgary, Brandon, and Winnipeg.
1890	Electric lights in Regina, Kenora, Portage La Prairie, and Moosejaw.
1891	Canadian Electrical Association formed.
1891	Edmonton Electric Light & Power Company begins operations.
1892	Canadian General Electric incorporated.

1892 Montreal's first hydroelectric plant established on the Lachine Canal.

1892 Canadian Niagara Power Company incorporated.

1892 Thomas L. "Carbide" Willson of Woodstock, Ontario, developed the electric-furnace process to manufacture calcium carbide.

1896 Marconi applied for a patent on wireless telegraphy.

1897 Hydroelectric power from Montmorency Falls supplies street lighting in Quebec City.

1897 Canadian branch of Westinghouse established at Hamilton.

1897 First long-distance, high-voltage transmission line (11 kV) carried power from St. Narcisse, to Trois-Rivières, Quebec — a distance of 29 km.

1898 Shawinigan Water & Power Company incorporated in Quebec.

1898 Royal Electric generated 15 MW at Chambly for transmission on 26 km to Montreal.

1900 Hydroelectric power distributed in all provinces except Prince Edward Island and Saskatchewan.

1900 Montreal Light, Heat & Power Company formed.

1900 Canada's installed hydroelectric capacity reached 133 MW.

1901 Yukon Electrical Company Limited founded.

1901 Trans-Atlantic wireless demonstrated from Newfoundland by Marconi.

1902 Edmonton Electric Light & Power Company becomes a municipal utility.

1902 Shawinigan aluminium plant produced conductors for the Shawinigan-Montreal transmission line.

1903 Shawinigan Water & Power installed the world's largest generator (5,000 hp) and transmitted power over the world's longest and highest voltage line — 136 km to Montreal at 50 kV.

1904 First significant exchange of power with the United States initiated at Niagara Falls.

1905 Ontario Hydro established.

1906 Hydroelectric power transmitted 96 km from the Winnipeg River to Winnipeg.

1910 Canada's installed hydroelectric capacity reached 700 MW.

1910 First 110-kV transmission line built from Niagara Falls to Dundas, Ontario.

1910 Quebec Streams Commission established.

1911 Calgary Power Co. Ltd. registered on March 17.

1918 New Brunswick Electric Power Commission created.

1918 Maritime Electric Company established.

1919 Ernest Rutherford of McGill University achieved atomic fission.

1919 Manitoba Power Commission established.

1919 Nova Scotia Power Commission established.

1921 Sir Adam Beck No.1 generating plant opened in Niagara Falls, then the largest in the world. Total capacity installed by 1924 was 528 MW.

1924 Newfoundland Light & Power Company established.

1928 World's first 10 000 kW, 3600 rpm steam-driven turbo generator installed at Edmonton Power's Rossdale generating station.

1929 Saskatchewan Power Corporation formed.

1930 Canada's installed generating capacity reached 4700 MW.

1940 The Canadian Standards Association assumed responsibility for approvals testing of electrical equipment.

1944 Hydro-Québec formed; acquired the facilities of the Montreal Light, Heat and Power Co.

1948 Northern Canada Power Commission created.

1949 Manitoba Hydro-Electric Board established.

1951 First 100-MW thermal generating unit installed.

1954 Newfoundland and Labrador Hydro created.

1956 First 315-kV transmission lines energized to carry power from Bersimis No.1 in north-eastern Quebec to Quebec City and Montreal.

1956 First tie-line between Manitoba and Ontario enters service for the interchange of power. The Seven Sisters-Kenora transmission line connected the northwestern system of Ontario Hydro and the southern system of Manitoba Hydro.

1957 Edmonton Power is the first Canadian utility to utilize a high-voltage (72 kV) high-pressure oil-filled pipe cable system.

1957 First Canadian pumping/generating station (capacity 177 MW) enters service at Niagara Falls.

1958 Great Lakes Power Company installed highest head (34 m) variable pitch blade Kaplan turbine in North America.

1960 Beauharnois (Quebec) first generating station to exceed 1000 MW installed. By 1986, installed capacity at this station reached 1639 MW.

1961 Largest single generating unit in Canada (300 MW) begins producing electricity at Ontario Hydro's Lakeview generating station.

1962 Saskatchewan Power installed first 25-kV underground residential distribution system.

1962 B.C. Hydro acquired the B.C. Electric Company.

1963 Hydro-Québec acquired private power companies, including Shawinigan Water & Power.

1963 Ratification of the Columbia River Treaty by Canada and the U.S. allowed B.C. Hydro to proceed with the construction of the Duncan, Keenleyside and Mica dams.

1965 First 735-kV transmission line from Manicouagan-Outardes to the Quebec load centres energized. At the time, it was the highest A.C. voltage in commercial use in the world.

1966 Development of the hydroelectric potential of the Nelson River in northern Mantitoba begins.

1967 First commercial-scale (220 MW) CANDU nuclear generating station in service at Douglas Point, Ontario.

1967 Ontario Hydro completes a 696-km, 500-kV transmission line from the Mattagami-Abitibi complex to Toronto.

1968 Power from Peace River transmitted to the B.C. lower mainland via a 918-km, 500-kV line.

1968 First Canadian DC transmission in service between Vancouver Island and the mainland at 260 kV.

1969 First 500-MW thermal generating unit operating at Lambton, Ontario.

1971 First two of four 542-MW nuclear generating units commissioned at Pickering, Ontario.

1971 First two units (500 MW and 475 MW) of the Churchill Falls, Labrador, hydroelectric station commissioned.

1971 Alberta Power established as the operating company for all of Canadian Utilities Limited's electric operations.

1972 An 880-km, 450-kV HVDC long-distance transmission system placed in commercial operation from the Nelson River to Winnipeg.

1972 World's largest solid-state high-voltage, direct-current (HVDC) converter/inverter terminal (320 MW) placed in service at Eel River, New Brunswick.

1973 Nova Scotia Power Commission became Nova Scotia Power Corporation, incorporating Nova Scotia Light & Power Company.

1974 Completion of the Churchill Falls generating station, with a total capacity of 5429 MW.

1974 Kettle hydro generating station, Manitoba Hydro's first generating station to be developed on the lower Nelson River, completed with a total capacity of 1272 MW.

1976 First 825-MW unit of the Bruce nuclear generating complex commissioned. (Total capacity of the complex is now 6600 MW.)

1978 New Brunswick-P.E.I. 100-MW submarine cable interconnection placed in service.

1979 First four 333-MW units of the LG 2 (James Bay) hydroelectric station placed in service by Hydro-Québec. (Total station capacity is 5328 MW, achieved by 1981.)

1983 A process to remove low-level PCBs from mineral oil is developed by Ontario Hydro.

1983 Point Lepreau No.1 nuclear power unit (680 MW) placed in service by N.B. Power at Point Lepreau, New Brunswick.

1984 First tidal power generating plant in North America placed in service by Nova Scotia Power at Annapolis Royal, Nova Scotia.

1986 TransAlta Utilities and B.C. Hydro commission 500-kV interconnection.

1986 The last unit (Unit 8) of Ontario Hydro's Pickering B nuclear station declared in service.

1987 Formation of the Yukon Energy Corporation.

1988 SaskPower completes the Athabasca transmission line, the longest line in its system. The 115-kV line stretches 355 km from near Uranium City to Rabbit Lake.

1988 Formation of the Northwest Territories Power Corporation.

1989 SaskPower and Alberta Power complete a 230 kV transmission line in Saskatchewan and 138 kV line in Alberta. It is the first Canadian link between the eastern and western power systems of North America.

1990 The first unit (Unit 2) of Ontario Hydro's Darlington nuclear station (4 x 881 MW) was commissioned.

1991 The Canadian Electrical Association celebrates its 100th birthday.

B2. Chronology of Regional Interconnections

Interconnection	Voltage (kV)	Date-in-Service
Quebec-Ontario	230	1928
Quebec-Ontario	115	1930 (1)
Quebec-Ontario	230	1932
Quebec-Ontario	115	1933 (1)
Quebec-Ontario	115	1940 (1)
Quebec-Ontario	230	1941
Quebec-Ontario	115	1942
Quebec-Ontario	115	1949
Quebec-Ontario	115	1949
Manitoba-Ontario	115	1956 (2)
Manitoba-Saskatchewan	230	1960
New Brunswick-Nova Scotia	138	1961
New Brunswick-Nova Scotia	138	1965
Quebec-New Brunswick	69	1965
Quebec-Ontario	115	1966
Quebec-Ontario	115	1966
Western Ontario-Eastern Ontario	230	1969
Labrador-Quebec	735	1971
Labrador-Quebec	735	1972
Western Ontario-Eastern Ontario	230	1972
Manitoba-Saskatchewan	230	1972
Manitoba-Ontario	230	1972
Quebec-New Brunswick	± 80 (DC)	1972
Quebec-New Brunswick	230	1972
Manitoba-Ontario	230	1973
Labrador-Quebec	735	1973
Alberta-British Columbia	138	1973
New Brunswick-Nova Scotia	345	1976 (3)
New Brunswick-Prince Edward Island	138	1977 (4)
New Brunswick-Prince Edward Island	138	1977 (4)
Manitoba-Saskatchewan	230	1979
Alberta-British Columbia	500	1985
Quebec-New Brunswick	± 80 (DC)	1985
Quebec-New Brunswick	345	1985
Saskatchewan-Alberta	230	1989

Notes: (1) *230 kV construction.* (2) *Constructed in 1931; interconnected in 1956.*
(3) *Operated at 138 kV until 1979.* (4) *Submarine cable.*

All interconnections are alternating current (AC), except for the Quebec-New Brunswick direct current (DC) facilities. All Quebec-Ontario interconnections and both Quebec-New Brunswick AC interconnections are radial (i.e. between one system and an isolated section of the other system).

APPENDIX C

C1. Remaining hydroelectric potential in Canada 139

Table C1. Remaining Hydroelectric Potential in Canada*

Sites	Gross Potential[1] (MW)	Identified Potential[2] (MW)	Planning Potential[3] (MW)	Capacity** Factor (%)
NEWFOUNDLAND				
Gull Island	1 698	1 698	1 698	76
Muskrat Falls	618	618	618	87
Lobstick	160	160	160	71
Pinware	77	77	-	67
Alexis	98	98	-	72
Paradise (Lab.)	89	89	-	66
Minipi	255	255	-	76
Fig	204	204	-	77
Eagle River	661	661	-	71
Naskaupi	290	290	-	73
Kaniriktok	394	394	-	75
Granite Canal	31	31	31	80
Island Pond	30	30	30	70
Round Pond	18	18	18	84
Sub Total	4 623	4 623	2 555	
OTHER SITES				
> 10 MW	186	-	-	61
< 10 MW	392	-	-	61
TOTAL ALL SITES	**5 201**	**4 623**	**2 555**	
NOVA SCOTIA				
> 10 MW	75	75	-	28
< 10 MW	15	15	-	54
Sub Total	90	90	-	
TIDAL				
Cumberland Basin	1428	1428	-	26
Minas Bassin	5338	5338	-	31
Shepody Bay	1643	1643	-	25
TOTAL ALL SITES	**8 499**	**8 499**	-	

Table C1. Remaining Hydroelectric Potential in Canada* (continued)

Sites	Gross Potential[1] (MW)	Identified Potential[2] (MW)	Planning Potential[3] (MW)	Capacity** Factor (%)
NEW BRUNSWICK				
Grand Falls (Ext)	300	300	300	21
Morrill	140	140	140	35
Green River	160	160	-	7
OTHER SITES	340	-	-	61
TOTAL ALL SITES	**940**	**600**	**440**	
QUEBEC				
Eastmain-1	510	510	510	63
Eastmain-2	200	200	-	74
Ste-Marguerite	822	822	822	58
Grande Baleine	2 891	2 891	2 891	60
Ashuapmushuan	776	550	550	75
NBR	8 700	8 700	8 700	61
Nastapoca	768	768	-	59
Sakami	187	187	-	79
La Romaine	1 710	1 710	1 710	59
Laforge-2	270	270	270	72
Haut St-Maurice	700	700	-	64
Matawin	212	212	-	75
Outaouais Sup.	281	281	-	45
Rapide-Manigance	78	78	-	88
Temiscamingue	195	195	-	53
Toulnoustouc	71	71	-	48
Aguanus	329	329	-	79
Magpie	354	354	-	79
Moisie	1 014	1 014	-	79
Musquaro	86	86	-	78
Natashquan	703	703	-	79
Olomane	300	300	-	80
Petit-Mecatina	1 754	1 754	-	59
St-Augustin	66	66	-	59
St-Paul	157	157	-	53
A-la-Baleine	807	807	-	78
Arnaud-Payne	592	592	-	67
Aux-Feuilles	711	711	-	80

Table C1. Remaining Hydroelectric Potential in Canada* (continued)

Sites	Gross Potential[1] (MW)	Identified Potential[2] (MW)	Planning Potential[3] (MW)	Capacity** Factor (%)
QUEBEC (cont'd)				
Caniapiscau	2 240	2 240	-	81
Eau-Claire	321	321	-	60
George	2 826	2 826	-	80
Harricana	1 032	1 032	-	80
Archipel	418	418	-	93
Other Ident. Sites	5 200	5 200	-	61
OTHER SITES	4 800	-	-	61
Sub total	42 081	37 055	15 453	
TIDAL	26 416	-	-	25
TOTAL ALL SITES	**68 497**	**37 055**	**15 453**	
ONTARIO				
Long Sault Rapids	52	52	52	52
Abitibi Canyon (Ext)	463	463	463	3
Newpost Creek	26	26	-	76
Otter Rapids (Ext)	174	174	174	3
Nine Mile Rapids	295	295	295	28
Sand Rapids	131	131	-	31
Allan Rapids	131	131	-	31
Ear Falls (Ext)	15	15	15	37
Maynard Falls	51	51	51	52
Little Jackfish	132	132	132	49
Highland Falls	94	94	-	18
Farm Rapids	13	13	-	52
Coral Rapids	192	192	-	19
Blacksmith Rapids	140	140	-	30
Upper Ten Mile Rapids	16	16	-	67
Yellow Falls	54	54	54	26
Cypress Falls	42	42	42	29
Little Long (Ext)	61	61	61	13
Smoky Falls (Redev)	182	182	182	32
Harmon (Ext)	68	68	68	16
Kipling (Ext)	68	68	68	16

Table C1. Remaining Hydroelectric Potential in Canada* (continued)

Sites	Gross Potential[1] (MW)	Identified Potential[2] (MW)	Planning Potential[3] (MW)	Capacity** Factor (%)
ONTARIO (cont'd)				
Grand Rapids	174	174	174	41
Thunderhouse Falls	42	42	-	48
Long Rapids	126	126	-	44
Mileage 66	81	81	-	40
Mileage 25	80	80	-	40
Patten Post	250	250	250	17
Ragged Chute (Redev)	98	98	98	21
Grey Goose	140	140	140	48
Renison	135	135	135	47
Adam Beck (Ext)	550	550	550	30
Paquette Rapids	29	29	-	89
Manitou Falls	58	58	-	17
Marathon	65	65	-	18
Spanish Site 4	80	80	-	38
Spanish Site 1	40	40	-	38
Denison Falls	36	36	-	29
Chicagouse Falls	28	28	-	38
Lower Ten Mile Rapids	19	19	-	67
Umbata Falls	51	51	-	40
Chigamiwingum Falls	57	57	-	41
Matabitchuan (Redev)	73	73	-	12
Alexander (Ext)	19	19	-	11
Cameron (Ext)	18	18	-	11
Pine Portage (Ext)	28	28	-	4
Chat Falls (Ext)	20	20	-	23
Chenaux (Ext)	196	196	-	5
Des Joachims (Ext)	348	348	-	5
Otto Holden (Ext)	203	203	-	3
Chaudiere Falls (Redev.)	72	72	-	66
Lake Temiscaming	24	24	-	73
Sub total	5 540	5 540	3 004	
OTHER SITES				
> 10 MW	5 480	5 480	360	53
< 10 MW	1 365	1 365	660	66
TOTAL ALL SITES	**12 385**	**12 385**	**4 024**	

Table C1. Remaining Hydroelectric Potential in Canada* (continued)

Sites	Gross Potential[1] (MW)	Identified Potential[2] (MW)	Planning Potential[3] (MW)	Capacity** Factor (%)
MANITOBA				
Conawapa	1 390	1 390	1 390	64
Gillam Island	1 000	1 000	1 000	65
Gull	650	650	650	64
Birthday	450	450	450	69
Red Rock	220	220	220	67
Whitemud	280	280	280	61
Granville Falls	150	150	150	61
First Rapids	190	190	190	78
Manasan	260	260	260	70
Wuskwatim	350	350	350	69
Notigi	100	100	100	68
Kelsey (Ext)	220	220	220	26
Sub total	5 260	5 260	5 260	
OTHER SITES				
> 10 MW	3000	-	-	61
< 10 MW	100	-	-	61
TOTAL ALL SITES	**8 360**	**5 260**	**5 260**	
SASKATCHEWAN				
Island Falls (Ext)	100	100	35	70
Wintego	285	285	285	60
Choiceland	150	150	150	40
Forks	400	400	400	40
Subtotal	935	935	870	
OTHER SITES	1 254	-	-	60
TOTAL ALL SITES	**2 189**	**935**	**870**	

Table C1. Remaining Hydroelectric Potential in Canada* (continued)

Sites	Gross Potential[1] (MW)	Identified Potential[2] (MW)	Planning Potential[3] (MW)	Capacity** Factor (%)
ALBERTA				
Berland	71	71	-	61
McLeod	36	36	-	61
McLeod Valley	22	22	-	61
Pembina	12	12	-	61
Cardinal	3	3	-	61
Elk	25	25	-	61
Frontal	19	19	-	61
Isaak	18	18	-	61
Job	4	4	-	61
Olympus	11	11	-	61
Race	8	8	-	61
Southesk Diversion	21	21	-	61
Strike	27	27	-	61
Thistle	25	25	-	61
Thunder	19	19	-	61
Horseguard	1	1	-	61
Brazeau Forks	88	88	-	61
Carvel	135	135	-	61
Chambers Creek	47	47	-	61
Drayton Valley	162	162	-	61
Gap	91	91	-	61
Hairy Hill	182	182	-	61
Phoenix	80	80	-	61
Ramparts	122	122	-	61
Rocky Mountain	49	49	-	61
Shunda	48	48	-	61
Whirlpool	10	10	-	61
Magnolia	7	7	-	61
Vermillion	12	12	-	61
Carcajou	1 329	1 329	-	61
Dunvegan	256	256	256	61
Mile 232	898	898	-	61
Mile 251	1 011	1 011	-	61
Vermillion Chutes	75	75	-	61
18th Baseline	210	210	-	61
19th Baseline	337	337	-	61
Bolton	124	124	-	61
Cutbank	174	174	-	61
Kakwa	346	346	-	61
Meander	292	292	-	61

Table C1. Remaining Hydroelectric Potential in Canada* (continued)

Sites	Gross Potential[1] (MW)	Identified Potential[2] (MW)	Planning Potential[3] (MW)	Capacity** Factor (%)
ALBERTA (cont'd)				
Peace River	253	253	-	61
Sulphur	84	84	-	61
Wapiti	228	228	-	61
Watino	346	346	-	61
West Watino	318	318	-	61
Dickson	7	7	-	61
Raven Dam Site	7	7	-	61
Alternative 4	1 667	1 667	1 667	61
Bassano	1	1	-	61
Cochrane	19	19	-	61
Dalemead	112	112	-	61
Eyremore	17	17	-	61
Glenbow	29	29	-	61
Lac des Arcs	15	15	-	61
Radnor	21	21	-	61
Russell	41	41	-	61
Shepard	78	78	-	61
Castle Site (1978)	7	7	-	61
Brocket	14	14	-	61
Fort MacLeod	7	7	-	61
Three Rivers	25	25	-	61
Meridan	45	45	-	61
Rapid Narrows	14	14	-	61
Subtotal	9 762	9 762	1 923	
OTHER POTENTIAL	9 051	-	-	61
TOTAL ALL SITES	**18 813**	**9 762**	**1 923**	
BRITISH COLUMBIA				
Peace Site C	900	900	900	60
Keenleyside	240	240	240	55
Murphy Creek	275	275	275	60
Stikine-Iskut	2 900	2 900	2 900	61
Liard River	4 318	4 318	3 190	66
Falls River (Redev)	15	15	15	36

Table C1. Remaining Hydroelectric Potential in Canada* (continued)

Sites	Gross Potential[1] (MW)	Identified Potential[2] (MW)	Planning Potential[3] (MW)	Capacity** Factor (%)
BRITISH COLUMBIA (cont'd)				
Seven Mile Unit 4	185	185	185	16
Homathko	895	895	710	55
Elaho	340	340	340	70
Border	250	250	250	74
McGregor Lower Canyon	360	360	360	62
Kemano Completion	520	520	520	60
Waneta (Ext)	380	380	380	28
Brilliant (Ext)	150	150	150	44
Shuswap	55	55	55	89
Beatrice Lake	31	31	31	68
Goat River	12	12	12	26
Peace Site E	600	600	-	53
Skeena	1 300	1 300	-	53
Yukon-Taku	3 700	3 700	-	67
Thorsen Creek	3	3	-	53
Duncan	25	25	25	48
OTHER SITES	14 969	-	-	61
Subtotal	32 423	17 454	10 538	
TIDAL				
Observation Inlet	660	660	-	35
Sechelt Inlet	54	54	-	35
TOTAL ALL SITES	**33 137**	**18 168**	**10 538**	
YUKON				
Mid Yukon	480	480	-	66
Hootalinqua	259	259	-	75
Wolverine	476	476	-	75
Detour Canyon	100	100	-	60
High Granite (III)	414	254	-	75
Braden Canyon	150	150	-	60
Big Salmon	301	301	-	75
Bell/Porcupine River	110	110	-	60
Frances, Upper Canyon	58	-	-	60

Table C1. Remaining Hydroelectric Potential in Canada* (continued)

Sites	Gross Potential[1] (MW)	Identified Potential[2] (MW)	Planning Potential[3] (MW)	Capacity** Factor (%)
YUKON (cont'd)				
Frances, False Canyon	170	58	58	60
Frances, Lower Canyon	80	75	75	60
Liard Basin	244	244	-	60
Liard Canyon	90	90	90	60
Aberdeen Falls	300	300	-	60
Bonnet Plumi	198	198	-	65
Porcupine Canyon	190	190	-	65
Porcupine Diversion	1 241	1 241	-	65
Porcupine/Stewart	83	83	-	60
Slate Rapids	42	42	42	60
Fraser Falls	300	300	-	60
Independence	450	450	-	60
Hoole Canyon	40	40	40	60
Hoole River	15	15	15	60
Ross Canyon	30	30	30	60
Primrose	30	30	-	60
Five Finger Rapids	455	150	-	75
Yukon-Taku	3 692	1 500	-	85
Yukon-Yaiya	4 050	2 000	-	85
Pelly Basin	160	160	-	60
Stewart Basin	150	150	-	60
Upper Canyon/White	16	16	-	60
Lower Canyon/White	16	16	-	60
Kluane Canyon	17	17	-	60
Britannia	459	459	-	75
Tatshenshine (I&II)	160	160	-	60
Donjek	43	43	-	60
Bates Canyon	110	110	-	60
Peel Diversion	755	755	-	65
Ogilvie	896	896	-	75
Dawson	571	571	-	75
Boundary	1 006	1 006	-	75
NWPI	55	55	-	60
Yukon River Basin	121	121	-	60
Subtotal	18 583	13 701	350	
Other sites	-	-	-	
TOTAL ALL SITES	**18 583**	**13 701**	**350**	

Table C1. Remaining Hydroelectric Potential in Canada* (continued)

Sites	Gross Potential[1] (MW)	Identified Potential[2] (MW)	Planning Potential[3] (MW)	Capacity** Factor (%)
N.W.T.				
Anderson	160	160	-	60
Back	2 073	2 073	1 162	60
Burnside	525	525	-	60
Camsell	29	29	-	60
Coppermine	279	279	149	60
Dubawnt River	178	178	-	60
Ferguson	16	16	-	60
Great Bear 1	438	438	204	60
Great Bear 2	414	414	-	60
Hornaday	91	91	-	60
Horton	115	115	-	60
Hayes	120	120	-	60
Hood	52	52	-	60
Kakisa	21	21	13	60
Kazan	64	64	-	60
Maguse	39	39	-	60
Nahanni/Virginia	232	232	216	60
Nahanni	339	339	-	60
Flat	18	18	-	60
Lockhart	387	387	126	60
Pikes Portage	148	148	126	60
Quoich	207	207	-	60
Tha-Anne	41	41	-	60
Taltson	113	113	34	60
Tazin	15	15	-	60
Thelon	188	188	34	60
Thlewiaza	73	73	-	60
Trout	10	10	6	60
Slave	1 130	1 130	370	60
Sylvia Grinnell	86	86	6	60
Snowdrift	6	6	-	60
Arctic Red	80	80	-	60
Peel	200	200	-	60
Rat	450	450	-	60
Keele	75	75	-	60
Mountain	70	70	-	60
Root	55	55	-	60
Redstone	135	135	-	60
Dahadinni	160	160	-	60
Willow Lake	20	20	-	60

Table C1. Remaining Hydroelectric Potential in Canada* (continued)

Sites	Gross Potential[1] (MW)	Identified Potential[2] (MW)	Planning Potential[3] (MW)	Capacity** Factor (%)
N.W.T. (cont'd)				
La Martre	27	27	27	60
Armshow	20	20	-	60
Anna Maria Port	7	7	-	60
Ward Inlet	15	15	-	60
Petitot	27	27	-	60
Hanbury	246	246	-	60
Prince	4	4	-	60
Maguse	3	3	-	60
Subtotal	9 201	9 201	2 473	
OTHER SITES	28	-	-	60
TOTAL ALL SITES	**9 229**	**9 201**	**2 473**	
CANADA TOTAL	**185 833**	**120 189**	**43 886**	

* *Estimated.*

1. *Gross Potential - The total gross resource that could be developed if there were no technical, economic or environmental constraints (excludes sites already developed or under construction).*
2. *Identified Potential - Gross potential less sites that may not be developed for technical reasons.*
3. *Planning Potential - Identified potential less sites that may not be developed for enviromental or economic reasons. The planning potential thus comprises all those sites that are considered to be likely candidates for future development.*

** *Capacity factors have been rounded off. In some cases, capacity factors have been estimated using 61 per cent for hydro and 25 per cent for tidal.*

Ext	*Extension.*
Redev	*Redevelopment.*

Source: Canadian electric utilities and Energy, Mines and Resources Canada.

APPENDIX D
FEDERAL ENVIRONMENTAL STANDARDS AND GUIDELINES

Recent amendments to the National Energy Board Act specify that the Board, in assessing applications for exports and international transmission lines, consider the potential impacts of projects on the environment. (See Chapter 3 for a detailed discussion of the regulatory process.) This appendix provides a brief overview of some federal environmental standards that, in addition to provincial environmental protection measures, may be particularly relevant to the assessment of such impacts.

Federal environmental standards are those that have been authorized or endorsed by the federal government and that apply where a project affects an area of explicit federal jurisdiction, such as navigable waters or migratory birds. Following a general discussion of types of environmental standards, the relevant federal standards are summarized briefly.[1]

TYPES OF ENVIRONMENTAL STANDARDS

Environmental standards are norms established with the overall objective of protecting both human and environmental health. For the purposes of this report, the term "environmental standards" will be used as a general reference to all environmental guidelines, objectives, limits, criteria and codes of practice. Federal environmental standards are grouped into three general categories for the purposes of discussion: ambient standards, emission standards and other standards.

Ambient Standards

Ambient standards are quantitative or qualitative statements describing a level of environmental quality that, if maintained in the "ambient" or open environment, will normally protect environmental and human health. Such standards generally specify concentrations of substances, or physical characteristics such as water temperature. Federal ambient standards normally have no legal force in themselves. They describe a level of environmental quality that may apply to specific designated regions, or to all regions of Canada. They serve as the goals or objectives towards which pollution-control initiatives, including legislation and regulations specifying emission standards, are directed.

Emission Standards

Emission standards refer to a limit on the quantity or quality of substances that may be released from industrial processes, based on the use of the best economically achievable technology. They usually specify a release rate or maximum concentration of a harmful substance that may be present in the emission as it emerges from its source: a smokestack, pipeline or landfill drainage system. Federal emission standards, which may be given force of law under regulations, are considered to be the minimum acceptable requirements for any industrial undertaking. More stringent emission standards may be required to meet appropriate ambient standards at a particular site.

Other Standards

Other standards include programs and legislation that provide for a wide variety of environmental protection measures, in addition to ambient or emission standards. Examples include the Environmental Codes of Practice for Steam Electric Power Generation and the Canadian Environmental Protection Act.

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[1] Greater detail on federal legislation, initiatives and standards may be obtained by contacting the Electricity Branch of Energy, Mines and Resources Canada.

OVERVIEW OF FEDERAL STANDARDS

1.1 Ambient Standards: Air

National Ambient Air Quality Objectives

The *National Ambient Air Quality Objectives*, published under the authority of the Canadian Environmental Protection Act (CEPA), specifies criteria for tolerable, acceptable and desirable levels of sulphur dioxide, nitrogen oxides, particulate matter, ozone and carbon monoxide in the open or ambient atmosphere.

Intergovernmental Agreements

Ambient standards are one method of implementing intergovernmental agreements to reduce and control air pollution. (For a general discussion of intergovernmental agreements on air pollution, see section 3.3 of this appendix.) The Government of Canada and the seven easterly provinces have signed federal-provincial agreements to reduce emissions of sulphur dioxide, based on a wet sulphate deposition target (ambient standard) of 20 kilograms per hectare per year.

1.2 Ambient Standards: Water

Water Quality Guidelines

The *Canadian Water Quality Guidelines*, published by the Canadian Council of Resource and Environment Ministers (CCREM), is an inventory of "water quality objectives" (ambient standards) suitable for different water uses in Canada, such as aquatic life, industrial processes, human consumption, recreational use and agricultural irrigation. These standards differ depending on the different water uses and must therefore be adapted to meet regional water quality needs. These standards are developed from existing guidelines where appropriate, such as the *Guidelines for Canadian Drinking Water Quality*, established by the Federal-Provincial Subcommittee on Drinking Water.

Intergovernmental Agreements

Canada has entered into an agreement with the United States (The Great Lakes Water Quality Agreement) to restore and maintain the water quality of the Great Lakes basin. To assist in meeting the goals of the Agreement, environmental quality objectives (ambient standards) were established for these waters.

Other regional ambient standards may be developed under federal-provincial agreements and programs enacted pursuant to the Canada Water Act.

2.1 Emission Standards: Air

Thermal Power Generation Emissions -- National Guidelines for New Stationary Sources

These guidelines, published under the authority of CEPA, are technology-based air emission standards for new fossil-fuelled electric generating stations. They are generic emission limitations recommended as minimum national standards that should be adopted by utilities and provincial governments. Criteria specified in the guidelines include those for sulphur dioxide, nitrogen oxide and particulate matter emissions, as well as for opacity (visibility standards).

2.2 Emission Standards: Water

The Environmental Codes of Practice for Steam Electric Power Generation

See Other Federal Standards, section 3.1, for a general description of the Codes of Practice.

The Design Phase Code of Practice recommends technology-based minimum waste water emission limitations. These standards specify effluent criteria for metals, oil and grease, chlorine, suspended solids and acidity, to minimize the total amount of contaminants discharged to surface waters. These criteria are of concern to aquatic and human life.

FEDERAL LEGISLATION: THE FISHERIES ACT, THE CANADA WATER ACT, AND THE MIGRATORY BIRDS ACT

The Fisheries Act prohibits the deposit of deleterious substances in any waters inhabited by fish. Regulations may limit the deposit of certain types of waste or substances in specific quantities and concentrations. Provisions are supported by Environment Canada's *Environmental Codes of Practice for Steam Electric Power Generation*. The Act also includes a broad range of environmental protection measures that cannot be adequately discussed in this short summary.

The Canada Water Act provides the federal government with the authority to regulate the emission of substances in designated "water quality management" areas. No regulations for water emissions have been implemented under this Act. The Act also provides the federal government with the authority to enter agreements with the provinces for water quality management.

Regulations pursuant to the Migratory Birds Act prohibit, in certain circumstances, the dumping of substances harmful to migratory birds in any water or area populated by these birds in Canada.

OTHER FEDERAL STANDARDS

3.1 Environmental Codes of Practice for Steam Electric Power Generation

The *Environmental Codes of Practice*, developed by a federal-provincial government and industry task force established by Environment Canada, contain recommendations judged to be reasonable and practical measures that can be taken to preserve the quality of the environment affected by fossil- and nuclear-fuelled electric power generation. Codes of practice now exist for the design, siting and construction phases of steam electric power generation projects. Although the design and siting phase codes have no legal status, the construction phase code is published under the authority of CEPA. Environment Canada is now developing codes for the operation and decommissioning phases of projects.

The various phases of the codes of practice, although treated in separate documents, are interdependent. To ensure environmental protection throughout the life of a steam electric power generating facility, the Codes should be considered as a whole.

3.2 Federal Legislation for the Control of Harmful Substances

The Canadian Environmental Protection Act provides authority for the control of harmful or toxic substances at any stage of the life-cycle of these substances, including development, manufacturing, storage, transportation, use and disposal. The Act specifies that the Minister of the Environment may develop environmental objectives (ambient standards), release guidelines (emission standards) and codes of practice, as well as enforceable regulations based on these and other environmental standards. Regulations include standards for the storage and disposal of polychlorinated biphenyls (PCBs).

The Transportation of Dangerous Goods Act authorizes the creation and enforcement of safety standards for transport, preparation for transport, and the related handling of dangerous goods (including PCBs and radioactive substances).

The Pest Control Products Act authorizes the development and enforcement of safety standards for the storage, handling and use of pesticides.

3.3 Intergovernmental Air Pollution Agreements

Canada is a signatory to two international protocols of the United Nations Economic Commission for Europe (ECE), under the 1979 Convention on Long-Range Transboundary Air Pollution. The protocols commit signatories to the reduction of sulphur dioxide emissions (1985) and nitrogen oxide emissions (1988). These protocols call for emission controls to reduce sulphur dioxide emissions by 30 per cent of 1980 levels by 1993, and to freeze emissions of nitrogen oxides at 1987 levels by 1994.

The protocol for the reduction of sulphur dioxide emissions has been implemented in Canada by individual agreements between the Government of Canada and the seven easterly provinces, to reduce emissions of sulphur dioxide by approximately 50 per cent of 1980 emissions by 1994. Consistent with the nitrogen-oxide protocol commitment, Canadian environment ministers are developing a comprehensive plan of action for the further management of nitrogen oxides and volatile organic compound emissions in Canada.

On March 13, 1991 the governments of Canada and the United States signed an agreement on air quality (the Air

Quality Accord). Among other things, Canada agreed to:

- Cap SO_2 emissions in the 7 easternmost provinces at 2.3 million tonnes per year from 1995 to 1999.
- Achieve a permanent national cap of 3.2 million tonnes per year by 2000.
- Reduce annual emissions of NO_x from stationary sources by 100 000 tonnes per year below the year 2000 forecast level of 970 000 tonnes per year.
- Develop, by January 1, 1995, further annual national emission reduction requirements from stationary sources to be achieved by 2000 and/or 2005.
- By January 1, 1995, estimate SO_2 and NO_x emissions from each new existing electric utility unit greater than 25 MW, using a method of comparable effectiveness to continuous emission monitoring.

3.4 General Environmental Standards for Nuclear Power Generation: Atomic Energy Control Board

See Chapter 3 for a general discussion of the regulatory function of the Atomic Energy Control Board (AECB).

The AECB's standards for licensing and monitoring nuclear facilities include regulations pursuant to the Atomic Energy Control Act for limiting radiation dosage to the public, and transportation standards for packaging and marking nuclear substances. The Board receives advice on environmental standards from Environment Canada and frequently conducts its licensing activities under a joint regulatory process involving federal and provincial environment authorities. The AECB coordinates its regulatory activities with the federal Environmental Assessment and Review Process (EARP) and any provincial environmental review process that may be required for nuclear facilities.

3.5 General Environmental Standards for Electricity Generation and Transmission for Export: National Energy Board

See Chapter 3 for details of the National Energy Board's regulatory process.

Applicants for a permit are required to submit information to the National Energy Board on the potential environmental impacts of the export or international transmission line. The Board will apply the procedures specified in the federal EARP Guidelines Order in determining whether to recommend designating an application for the licensing or certification process. When a licence hearing is necessary, applicants may be required to undertake a detailed analysis of the project, including among other things, environmental considerations.

3.6 Federal Environmental Assessment and Review Process Guidelines Order

See Chapter 4 for details of the federal EARP.

The Guidelines Order sets out standard procedures that should be followed by federal government departments in conducting an initial screening of projects under their authority for significant environmental effects.

APPENDIX E

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E1. Current and proposed electrical efficiency-improvement programs offered by Canadian electrical utilities

AGRICULTURAL PROGRAMS

1. Several specific programs are in place to increase energy efficiency in P.E.I.'s agricultural sector.

RESIDENTIAL PROGRAMS

1. New home construction -- promotion of minimum efficiency standards for new residential buildings, labelling of energy-efficient homes, and sponsoring builder training programs.
2. Building upgrades -- consumers provided with technical information, audits and financial assistance to carry out energy efficiency activities in electrically heated homes.
3. Improving appliance efficiency -- promotion of minimum energy efficiency standards for appliances, labelling of energy-efficient appliances, consumer education, promotion, financial incentives for retailers, rebates for purchases of efficient equipment including timers for block heaters and thermostats, buybacks of inefficient equipment, water-heater tune-ups and give-aways of water-heater insulation and water saving devices.
4. Fuel conversion -- promotion of alternative fuels to electricity as the fuel of choice for new and existing spaceand water heating, incentives offered to consumers who switch from electrical space or water heating to other forms of heating systems.

COMMERCIAL PROGRAMS

1. New building construction -- promotion of minimum efficiency standards for new commercial buildings, labelling of efficient buildings, and financial incentives to owners, designers and builders to develop energy-efficient designs.
2. Building retrofit -- technical information, audit and financial assistance for upgrades to existing commercial buildings, including envelope (i.e. HVAC, water heating, heat recovery, refrigeration and other electrical equipment), as well as purchases of energy-management equipment.
3. Fuel conversion -- promotion of alternative fuels to electricity as the fuel of choice for new and existing commercial buildings.

INDUSTRIAL PROGRAMS

1. New building construction -- promotion of energy efficiency in new industrial plant design.
2. Plant retrofit -- education, promotion, field support, audits, and technical and financial assistance provided to industrial customers to evaluate and implement improvements in plant energy efficiency.
3. High-efficiency and adjustable speed drive motors -- education, promotion and rebates for installation of high-efficiency motors and drives in new and replacement situations.

E1. Current and proposed electrical efficiency-improvement programs offered by Canadian electrical utilities (continued)

4. Pressurized air-piping systems -- leak test on compressed air systems.
5. Energy-efficient lighting -- education, promotion and incentives for purchases and conversions of energy-efficient lighting, including conversions of existing roadway lighting to more efficient high-pressure sodium lighting.
6. Fuel Conversion -- Electrotechnologies
7. Process Improvements

E2. Load-shifting programs

1. TIME-OF-USE RATES -- The cost of providing electricity varies throughout the year, the week, and the hours of the day. This is because different load requirements necessitate the use of different mixes of generating facilities. Those facilities with the highest variable costs are generally operated only to meet peak-load requirements. Time-of-use rates are designed to reflect these increased costs of electricity supply during the seasonal or daily peak. They are intended to encourage more efficient use of the electrical system while offering customers financial rewards, in the form of reduced rates, for managing their loads between peak and off-peak periods. The utility benefits by reducing its seasonal and daily peaks.

   While time-of-use concepts are embedded in a number of Canadian utility rate structures, and particularly in relation to large industrial and commercial users, Ontario Hydro, SaskPower, and Maritime Electric are the only Canadian electrical utilities that have implemented time-of-use rates. Ontario Hydro has established four time-of-use periods: winter peak, winter off-peak, summer peak, and summer off-peak. Summer consists of the months of April through September inclusive, with winter being the months of October to March. The peak period in each season extends from 7 a.m. to 11 p.m., Monday to Friday, except for public holidays. All other hours are off-peak. The rates apply to Ontario Hydro's large industrial customers, large customers of the municipal utilities served by Ontario Hydro, and on a voluntary basis to municipal utilities themselves. Eighty per cent of Ontario Hydro's electrical load is now on time-of-use rates. The design of time-of-use rates in Saskatchewan and Prince Edward Island are much simpler than those of Ontario.

2. LOAD-CONTROL PROGRAMS -- Direct control of customer load is another means to shift load from peak to off-peak periods. Equipment is installed to enable the utility to control electrical loads through the day. The most common application is to space and water heating, whereby electricity for these purposes is managed to reduce peak and smooth the overall load.

3. HEAT-STORAGE/COOL-STORAGE PROGRAMS -- Utilities can shift daytime loads to nighttime by providing incentives for customers to purchase thermal storage systems. Once the thermal storage system is in operation, electricity is used during the night to either make ice or heat, a medium which is used through the day for either space or water heating.

4. DUAL-ENERGY PROGRAMS -- These types of programs involve both peak shifting and valley filling. Dual-energy programs generally apply to consumers that can rely on a second energy form for space or water heating. The utility offers a reduced price for off-peak consumption on the understanding that during peak periods the consumer is to rely on an alternative energy source, e.g. natural gas or oil-fired heating. Any peak period electrical consumption by consumers participating in the program is at a much higher rate.

E.3. Prices paid by major electric utilities for non-utility generation in 1992

Major Electric Utility	Purchase Rates	Pricing Formula	Remarks
Newfoundland and Labrador Hydro	Depends on system.	Based upon "share the savings" principle up to a maximum of 90% of the avoided fuel cost.	Purchases, for isolated areas are evaluated based on the size of the system under consideration.
	Rate has yet to be published.	Average incremental cost.	Purchases for interconnected areas.
Newfoundland Light & Power Co. Ltd.	Negotiable.	Negotiation up to the system incremental cost of generation.	Surplus sales are purchased at a price lower than the short-run marginal cost.
Maritime Electric	2.825 cents/kW.h (in 1991)	Average purchase price of economy energy from New Brunswick Power.	
Nova Scotia Power	Capacity: 2.79 cents/kW.h Energy: 3.49 cents/kW.h	Full avoided cost based on system simulations.	Contract term for 10 years. Plants on-line during 1993-94 fiscal year.
	Capacity: 3.68 cents/kW.h Energy: 3.49 cents/kW.h	Proxy unit used to develop rates. Proxy unit is a 3x165 MW CFB plant plus associated transmission.	Contract term for 33 years. Capacity rate is fixed for term. Energy rate is based on actual proxy unit fuel and operating and maintenance. Plants on-line during 1993-94 fiscal year.
NB Power	Existing dedicated suppliers: Peak: 4.9 cents/kW.h. (1992 $) Off-peak: 2.8 cents/kW.h. (1992 $)	Peak hours: 100% of NB Power's full avoided cost (capacity and energy). Off-peak hours: NB Power's full avoided energy costs.	Installed capacity is less than 5 MW. Contract length is greater than one year. Peak hours are from 0700 to 2100. Peak months are from December to March.
	Non-dedicated suppliers: 1.8 cents/kW.h. (1992 $)	90% of NB Power's hourly average system decremental cost.	
	Future dedicated suppliers: 6.4 cents/kWh (1996 $)	Avoided cost.	Installed capacity is larger than 5 MW. Contract length should be greater than 3 years.
Hydro-Québec	4.4 cents/kW.h (1992 $)	Avoided cost.	The price is for high tension (greater or equal to 50 kV) and will be adjusted by the Consumer Price Index at a maximum of 6% and at a minimum of 3%.

E.3. Prices paid by major electric utilites for non-utility generation in 1992 (continued)

Major Electric Utility	Purchase Rates	Pricing Formula	Remarks
	4.6 cents/kW.h (1992 $)	Avoided cost.	The price is for an average tension (750 to 50 kV) and will be adjusted by the Consumer Price Index at a maximum of 6% and at a minimum of 3%.
Ontario Hydro	Projects up to 5 MW:		
	Option 1 - Basic purchase rate schedule offered to non-utility generators regardless of the fuel or technology used.	Avoided cost.	To qualify for Option 1, a non-utility generator would have to enter into a contract with Ontario Hydro for a typical term of 20 years.
	Winter peak: 7.36 cents/kW.h	Peak rates are based on Ontario Hydro's 20-year incremental capacity and energy costs.	All time-differentiated rates adjusted annually at Ontario's CPI.
	Winter off-peak: 3.00 cents/kW.h	Off-peak rates are based on incremental energy cost.	Capacity factor is not a criterion in setting the rates.
	Summer peak: 5.97 cents/kW.h		
	Summer off-peak: 2.66 cents/kW.h		
	Option 2 - Premium rates to projects that use renewable resources or use high efficiency energy conversion technology.	In principle, the pricing formula is the same as Option 1 above.	
	Winter peak: 8.10 cents/kW.h		
	Winter off-peak: 3.30 cents/kW.h		
	Summer peak: 6.57 cents/kW.h		
	Summer off-peak: 2.93 cents/kW.h		
	Option 3 - 10 year fixed rate to renewable resource-based projects:	In principle, the pricing formula is the same as Option 1 above.	

E.3. Prices paid by major electric utilities for non-utility generation in 1992 (continued)

Major Electric Utility	Purchase Rates	Pricing Formula	Remarks
	Winter peak: 9.81 cents/kW.h		
	Winter off-peak: 3.99 cents/kW.h		
	Summer peak: 7.96 cents/kW.h		
	Summer off-peak: 3.55 cents/kW.h		
	Projects delivering over 5 MW net.	Avoided cost.	To be reviewed project-by-project.
Manitoba Hydro	To be negotiated.		Policies have not been finalized.
SaskPower	Not available at this time.		Policy is under review.
TransAlta Utilities Alberta Power Edmonton Power, and The City of Medicine Hat	5.2 cents/kW.h (fixed from 1990 to 1994), increasing to 6.0 cents/kW.h (fixed from 1995 to 1999), or 4.64 cents/kW.h starting in 1990, escalating with inflation.	Legislated rates.	These rates are applied to small power producers using renewable resources such as wind, hydro, and biomass. Projects are up to 2.5 MW. A limited number of pilot projects in excess of 2.5 MW may be approved.
	Energy from non-traditional sources such as generators powered by flare gas or co-generators.	To be negotiated.	
B.C. Hydro	Projects with a capacity of less than 5 MW.	80% of B.C. Hydro's avoided cost.	Total annual purchase limited to 25 MW. Co-generation or self-generation.
	Projects with a capacity of 5 MW or more.	To be negotiated.	

Source: Major electric utilities, March 1992.

DEFINITIONS AND ABBREVIATIONS

Alternating Current (AC): A current that flows alternately in one direction and then in the reverse direction. In North America the standard for alternating current is 60 complete cycles each second. Such electricity is said to have a frequency of 60 hertz. Alternating current is used universally in power systems because it can be transmitted and distributed much more economically than direct current.

Base Load: The minimum continuous load over a given period of time.

British Thermal Unit (BTu): A unit of heat. The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

Capacity: In the electric power industry, capacity has two meanings:

1. System Capacity: The maximum power capability of a system. For example, a utility system might have a rated capacity of 5000 megawatts, or might sell 50 megawatts of capacity (i.e. of power).

2. Equipment Capacity: The maximum power capability of a piece of equipment. For example, a generating unit might have a rated capacity of 50 megawatts.

Capacity Factor: For any equipment, the ratio of the average load during some time period to the rated capacity.

Cogeneration: A cogenerating system produces electricity and heat in tandem. Such systems have great potential in industry, where a significant requirement for electricity is coupled with a large demand for process steam.

Consumer Price Index (CPI): A measure of the percentage change over time in the cost of purchasing a constant "basket" of goods and services. The basket consists of items for which there are continually measurable market prices, so that changes in the cost of the basket are due only to price movements.

Consumption: Use of electrical energy, typically measured in kilowatt hours.

Conventional Generation: Electricity that is produced at a generating station where the prime movers are driven by gases or steam produced by burning fossil fuels.

DEFINITIONS AND ABBREVIATIONS

Current: The flow of electricity in a conductor. Current is measured in amperes.

Demand Charge: The component of a two-part price for electricity that is based on a customer's highest power demand reached in a specified period, usually a month, regardless of the quantity of energy used (e.g. $2.00 per kilowatt per month). The other component of the two-part price is the energy charge.

Direct Current (DC): Current that flows continuously in the same direction (as opposed to alternating current). The current supplied from a battery is direct current.

Economy Energy: Energy sold by one power system to another, to effect a saving in the cost of generation when the receiving party has adequate capacity to supply the loads from its own system.

Electrical Energy: The quantity of electricity delivered over a period of time. The commonly used unit of electrical energy is the kilowatt-hour (kW.h).

Electrical Power: The rate of delivery of electrical energy and the most frequently used measure of capacity. The basic unit is the kilowatt (kW).

Energy Charge: The component of a two-part price for electricity which is based on the amount of energy taken (e.g. 20 mills per kW.h). The other component of the price is the demand charge.

Energy Source: The primary source that provides the power that is converted to electricity. Energy sources include coal, petroleum and petroleum products, gas, water, uranium, wind, sunlight, geothermal, and other sources.

Firm Energy or Power: Electrical energy or power intended to be available at all times during the period of the agreement for its sale.

Frequency: The number of cycles through which an alternating current passes in a second. The North American standard is 60 cycles per second, known as 60 hertz.

DEFINITIONS AND ABBREVIATIONS

Gigawatt (GW): One billion watts. (See Watt.)

Gigawatt hour (GW.h): A unit of bulk energy. A million kilowatt hours. A billion watt hours.

Grid: A network of electric power lines and connections.

Gross Domestic Product (GDP): The total value of goods and services produced in Canada. GDP measured in constant dollars is defined as Real GDP.

Gross National Product (GNP): The total value of production of goods and services measured at market prices.

Hertz (Hz): The unit of frequency for alternating current. Formerly called cycles per second. The standard frequency for power supply in North America is 60 Hz.

Installed Capacity: The capacity measured at the output terminals of all the generating units in a station, without deducting station service requirements.

Interruptible Energy or Power: Energy or power made available under an agreement that permits curtailment or interruption of delivery at the option of the supplier.

Joule: The international unit of energy. The energy produced by a power of one watt flowing for one second. The joule is a very small unit: there are 3.6 million joules in a kilowatt hour.

Kilovolt (kV): 1000 volts.

Kilowatt (kW): The commercial unit of electric power; 1000 watts. A kilowatt can best be visualized as the total amount of power needed to light ten 100-watt light bulbs.

DEFINITIONS AND ABBREVIATIONS

Kilowatt hour (kW.h): The commercial unit of electric energy; 1000 watt hours. A kilowatt hour can best be visualized as the amount of electricity consumed by ten 100-watt light bulbs burning for an hour. One kilowatt hour is equal to 3.6 million joules.

Load: The amount of electric power or energy consumed by a particular customer or group of customers.

Load Factor: The ratio of the average load during a designated period to the peak or maximum load in that same period. (Usually expressed in per cent.)

Megawatt (MW): A unit of bulk power; 1000 kilowatts.

Megawatt hour (MW.h): A unit of bulk energy; 1000 kilowatt hours.

Mill: 1/1000 of a dollar.

Net Exports: Total exports minus total imports.

Nuclear Power: Power generated at a station where the steam to drive the turbines is produced by an atomic process, rather than by burning a combustible fuel such as coal, oil or gas.

Peak Demand: The maximum power demand registered by a customer or a group of customers or a system in a stated period of time such as a month or a year. The value may be the maximum instantaneous load or more, usually the average load over a designated interval of time, such as one hour, and is normally stated in kilowatts or megawatts.

Power System: All the interconnected facilities of an electrical utility. A power system includes all the generation, transmission, distribution, transformation, and protective components necessary to provide service to the customers.

Primary Energy Source: The source of primary energy from which electricity is generated. This may be falling water, uranium (by nuclear fission), coal, oil, natural gas, wind, tidal energy, etc.

DEFINITIONS AND ABBREVIATIONS

Reserve Generating Capacity: The extra generating capacity required on any power system over and above the expected peak load. Such a reserve is required mainly for two reasons: (i) in case of an unexpected breakdown of generating equipment; (ii) in case the actual peak load is higher than forecast.

Terawatt Hours (TW.h): One billion kilowatt hours.

Voltage: The electrical force or potential that causes a current to flow in a circuit (just as pressure causes water to flow in a pipe). Voltage is measured in volts (V) or kilovolts (kV). 1 kV = 1000 V.

Watt: The scientific unit of electric power; a rate of doing work at the rate of one joule per second. A typical light bulb is rated 25, 40, 60 or 100 watts, meaning that it consumes that amount of power when illuminated. A horse power is 746 watts.